

Minimum Filing Requirements

SaskPower 2026 and 2027 Rate Application

Tab

1. Latest Annual Report
2. Current Organization Structure
3. Corporate Long-Term and Strategic Plans
4. Current Supply Plan
5. Most recent Economic Report for Saskatchewan prepared by independent third party
6. Rate Application Document
 - Rate Changes Requested in Detail including details of any new rates or rate options
 - Current and Anticipated Fuel Costs & Anticipated Hydro Energy Capacity together with energy supply contacts (imports/exports)
 - Operating, Maintenance and Administrative Costs
 - Financial Information (Including Capital Structure and Cost of Capital)
 - Taxes
 - Current Rate Structure, Classification System and Revenue to Cost Ratios
 - Existing Service Levels on a Comparative Basis
 - Rate Base and its Derivation
 - Current historical and Projected Return on Equity
 - Most recent quarterly financial report and financial updates as deemed appropriate or necessary
7. Load Forecasts (Including High and Low Scenarios) together the three-years actual load data
8. Latest actual and current prospective Cost of Service and Allocation Study Reports together with the latest external Cost of Service Study and methodologies in use
9. Past, Current and Future Staff Levels by Division
10. Report on Implementation of Previous Panel Recommendations
11. The most recent risk assessment for SPC
12. Comparison of SPC rates/competitive factors relative to other Canadian Utilities

Section 1: Latest Annual Report

ANNUAL REPORT



2024 - 25

ON THE COVER: GREAT PLAINS POWER STATION

On December 17, 2024, SaskPower's new 370-megawatt (MW) natural gas-fired Great Plains Power Station (Great Plains) officially began delivering power to the Saskatchewan grid. As a combined-cycle natural gas-fired station, Great Plains is a key pillar in SaskPower's long-term strategy to modernize and expand the provincial electrical system, while also maintaining affordable rates that support the province's ongoing economic growth. In planning for Saskatchewan's energy future, natural

gas-fired generation will be critical in ensuring we maintain a balanced electrical system, with coal, nuclear reactors, battery storage, and renewable generation also playing a potential role in responding to the challenge. Construction activity at Great Plains, which occurred over three years, included more than 300 Saskatchewan companies and contributed more than \$260 million to the local and provincial economies, and nearly \$50 million to Indigenous companies.



GREAT PLAINS POWER STATION

CORPORATE PROFILE

Established in 1929, SaskPower is Saskatchewan's leading energy supplier. We are defined by our commitment to support economic growth and enhance the quality of life in our province. Our corporate mission: ensuring reliable and affordable power for our customers and the communities we serve.

SaskPower's team is made up of nearly 3,300 permanent full-time employees. We manage almost \$15 billion in generation, transmission, distribution and other assets. Our company operates eight natural gas-fired power stations, three coal-fired power stations, seven hydroelectric stations, and two wind facilities. Combined, they generate 4,241 MW of electricity. SaskPower also buys power from various independent power producers. Our company's total available generation capacity is 5,930 MW.

We are responsible for serving over 560,000 customer accounts within Saskatchewan's geographic area of approximately 652,000 square kilometres. We maintain nearly 160,000 circuit kilometres of power lines, 65 high voltage switching stations and 191 distribution substations. Just over three customer accounts are served per circuit kilometre.

Our company also has transmission interties at the Manitoba, Alberta and North Dakota borders.

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SaskPower's 2024-25 Annual Report reflects the fiscal period April 1, 2024, through March 31, 2025.

OUR STRATEGIC CONTEXT

OUR VISION

Powering Saskatchewan's energy future through innovation, performance and service.

OUR MISSION

Ensuring reliable and affordable power for our customers and the communities we serve.

OUR VALUES

Safety, openness, collaboration and accountability.

CORPORATE GOALS

DELIVER IMPROVED VALUE FOR OUR CUSTOMERS AND STAKEHOLDERS
[p 19]

DEVELOP THE WORKFORCE TO MEET OUR FUTURE NEEDS
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ENSURE OUR FINANCIAL HEALTH
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BUILD A RELIABLE, SECURE AND AFFORDABLE ELECTRICITY SYSTEM FOR THE FUTURE
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PERFORMANCE HIGHLIGHTS

FINANCIAL INDICATORS

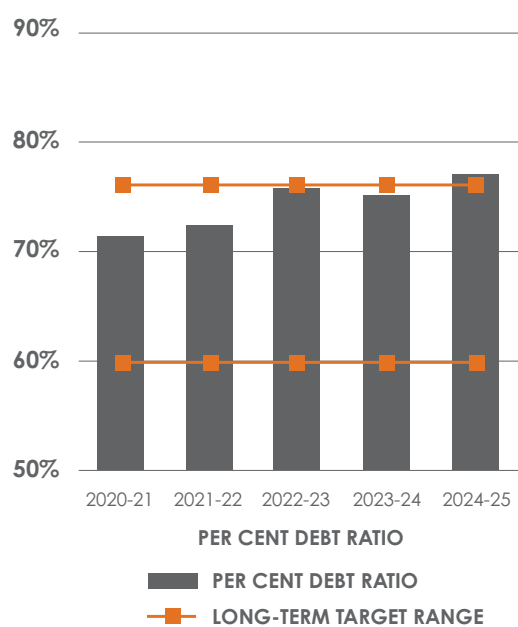
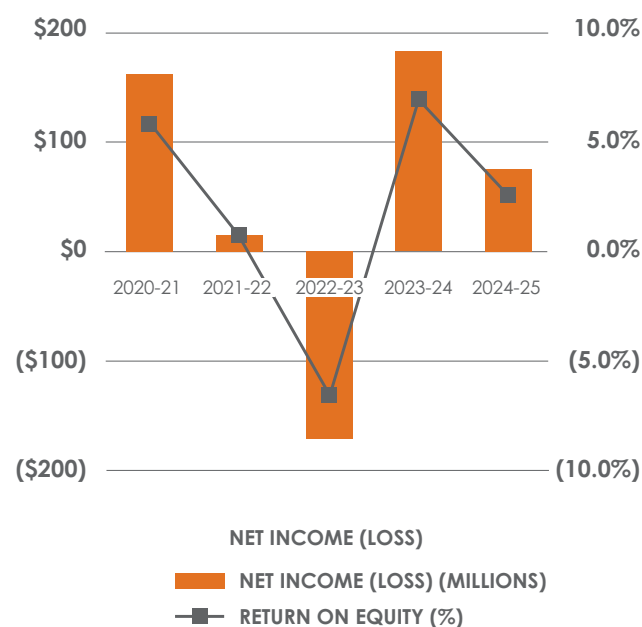
(in millions)	2024-25	2023-24	Change
Revenue	\$ 3,254	\$ 3,379	\$ (125)
Expense	3,178	3,195	(17)
Net income	76	184	(108)
Total capital expenditures	1,497	1,213	284
Net cash from operating activities	481	751	(270)
Return on equity ¹	2.6%	6.7%	(4.1%)
	March 31 2025	March 31 2024	Change
Long-term debt	\$ 8,468	\$ 7,647	\$ 821
Short-term advances	809	910	(101)
Lease liabilities	984	850	134
Total debt	\$ 10,261	\$ 9,407	\$ 854
Debt retirement funds	931	799	132
Cash and cash equivalents	50	374	(324)
Total net debt	\$ 9,280	\$ 8,234	\$ 1,046
Retained earnings	2,313	2,237	76
Equity advances	593	593	-
Total capital	\$ 12,186	\$ 11,064	\$ 1,122
Per cent debt ratio ²	76.2%	74.4%	1.8%

\$76M
NET INCOME

76.2%
PER CENT DEBT RATIO

1. Return on equity = (net income)/(average equity), where equity = (retained earnings + equity advances).

2. Per cent debt ratio = (total net debt)/(total capital).



REVENUE HIGHLIGHTS

(in millions)	2024-25	2023-24	Change
Saskatchewan electricity sales			
Residential	\$ 637	\$ 632	\$ 5
Farm	188	198	(10)
Commercial	557	557	-
Oilfield	477	469	8
Power	879	895	(16)
Reseller	104	105	(1)
	\$ 2,842	\$ 2,856	\$ (14)
Federal carbon charge collected	268	240	28
	\$ 3,110	\$ 3,096	\$ 14

23,984
GWh

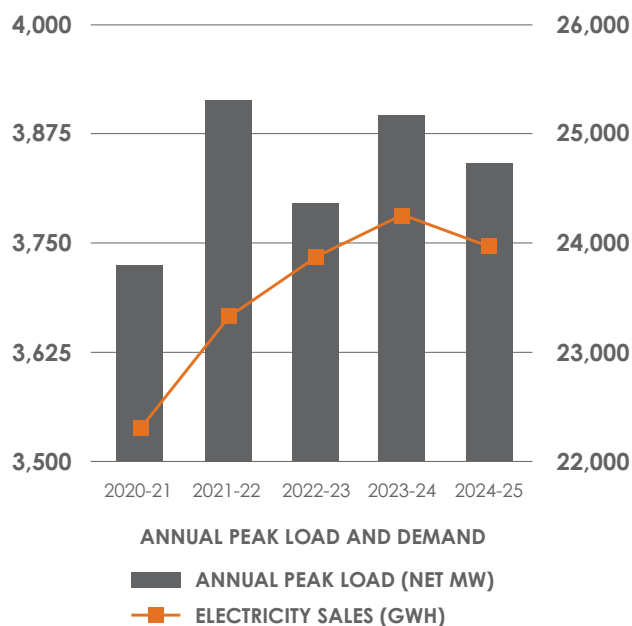
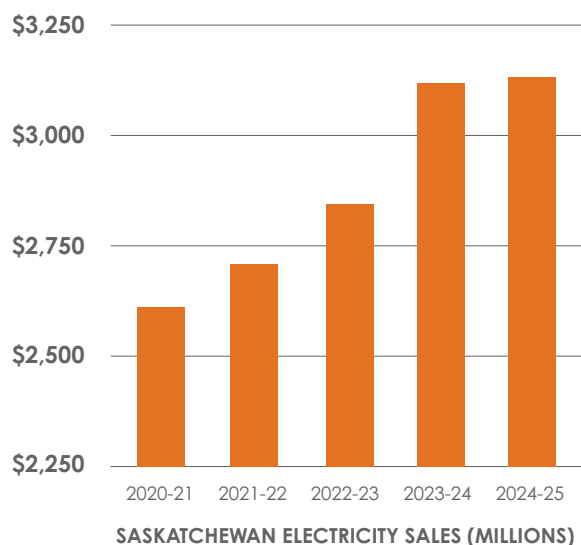
ELECTRICITY SALES

562,232

CUSTOMER ACCOUNTS

(in GWh)	2024-25	2023-24	Change
Electricity sales volumes			
Residential	3,248	3,224	24
Farm	1,226	1,305	(79)
Commercial	3,744	3,749	(5)
Oilfield	4,395	4,320	75
Power	10,228	10,531	(303)
Reseller	1,143	1,150	(7)
	23,984	24,279	(295)

	2024-25	Record
Summer peak load (net megawatts (MW))	3,669	3,669
Annual peak load (net MW)	3,838	3,910



FUEL HIGHLIGHTS AND GENERATING CAPACITY

(in millions)	2024-25	2023-24	Change
Fuel and purchased power			
Gas	\$ 316	\$ 366	\$ (50)
Coal	313	296	17
Imports	173	178	(5)
Wind	108	84	24
Hydro	18	16	2
Solar	8	6	2
Other	25	25	-
	\$ 961	\$ 971	\$ (10)
Federal carbon charge	280	269	11
Grant funding	(136)	-	(136)
	\$ 1,105	\$ 1,240	\$ (135)

(in GWh)	2024-25	2023-24	Change
Gross electricity supplied			
Gas	12,426	11,934	492
Coal	6,245	7,895	(1,650)
Imports	1,929	2,027	(98)
Wind	2,531	1,981	550
Hydro	2,769	2,490	279
Solar	94	71	23
Other	180	177	3
	26,174	26,575	(401)

(in net MW)	2024-25	2023-24	Change
Available generating capacity			
Fossil fuel generating capacity	3,823	3,454	369
Renewable generating capacity	2,107	1,901	206
	5,930	5,355	575

5,930 MW
AVAILABLE GENERATING
CAPACITY

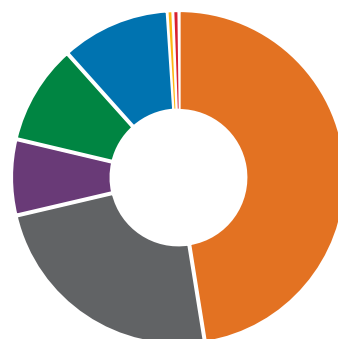
35.5%

RENEWABLE GENERATION
CAPACITY



2024-25 AVAILABLE GENERATING CAPACITY
5,930 NET MW

■ GAS 41% ■ COAL 23%
■ HYDRO 19% ■ WIND 14%
■ SOLAR 2% ■ OTHER 1%



2024-25 GROSS ELECTRICITY SUPPLIED
26,174 GWH

■ GAS 47% ■ COAL 24%
■ IMPORTS 7% ■ WIND 10%
■ HYDRO 11% ■ SOLAR <1%
■ OTHER <1%

TRANSMISSION AND DISTRIBUTION HIGHLIGHTS

Transmission and distribution assets

Service area (square kilometres (km))	652,000
Transmission lines ¹ (circuit km)	14,816
Distribution lines ¹ (circuit km)	144,868
Distribution poles	1,161,386
High voltage switching stations	65
Distribution substations	191
Pole, pad-mounted and step transformers	190,654

1. Transmission lines deliver 66 kilovolts (kV) or above while distribution lines deliver less than 35 kV.

159,684
CIRCUIT KM

TRANSMISSION AND
DISTRIBUTION LINES

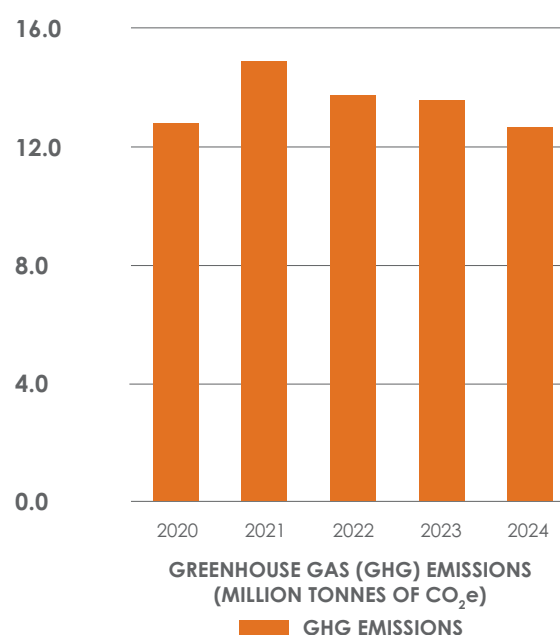
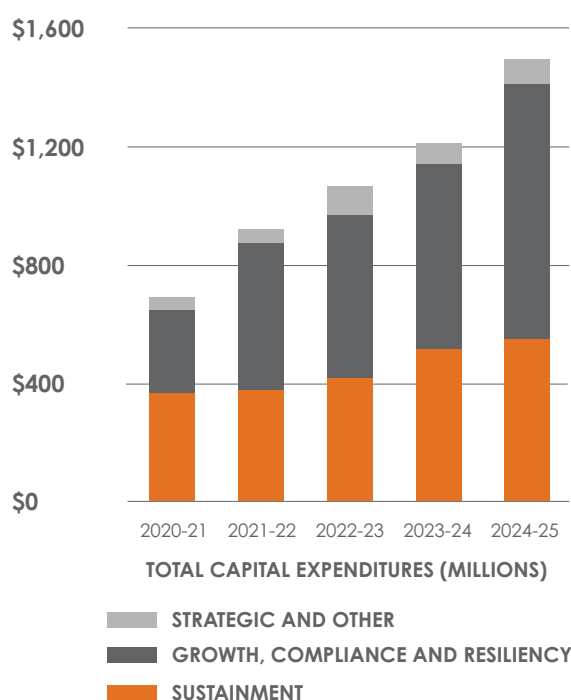
CAPITAL HIGHLIGHTS

(in millions)	2020-21	2021-22	2022-23	2023-24	2024-25
Sustainment	\$ 366	\$ 385	\$ 421	\$ 520	\$ 555
Growth, compliance and resiliency	286	490	552	621	855
Strategic and other	41	47	92	72	87
Total capital expenditures	\$ 693	\$ 922	\$ 1,065	\$ 1,213	\$ 1,497
Grant funding ²	-	-	(18)	(49)	(74)
Capital expenditures (net)	\$ 693	\$ 922	\$ 1,047	\$ 1,164	\$ 1,423

2. Total capital expenditures prior to 2022-23 is reported net of grant funding provided.

\$1.5B

TOTAL CAPITAL
EXPENDITURES



2024-25 YEAR AT A GLANCE

- ⚡ **ACHIEVED** commercial operation of our 370-MW natural gas-fired Great Plains Power Station in December 2024.
- ⚡ **COMMENCED** construction of the new 370-MW natural gas-fired Aspen Power Station near Lanigan. It is expected to reach commercial operation by the end of 2027.
- ⚡ **ESTABLISHED** a new wholly owned subsidiary called SaskNuclear to advance our nuclear small modular reactor project through the regulatory and licensing process.
- ⚡ **COMPLETED** our first custom-built community microgrid in April 2025, which is providing power to the small northern community of Descharme Lake. The independent solar-battery-diesel combination microgrid will provide safe and reliable power for the community year-round and in all weather conditions.
- ⚡ **EXPANDED** our company's wind power capacity by 200 MW at the end of 2024 with the addition of the Bekevar Wind Power Facility.
- ⚡ **CELEBRATED** 10 years of operation at our carbon capture and storage facility at Boundary Dam Power Station Unit 3.
- ⚡ **REINTRODUCED** the Energy Efficiency Discounts Program to provide instant savings on select energy efficiency purchases. We also expanded the offering to include dishwashers, washing machines and home insulation.
- ⚡ **INTRODUCED** the Commercial Energy Optimization Program, which focuses on the size and needs of a participating business and provides customized service offerings that range from no-cost energy reduction strategies and opportunities to free energy management coaching, as well as financial incentives for upgrading facilities with more efficient equipment.
- ⚡ **LAUNCHED** the Indigenous New Homes Rebate Program, which offers financial support for eligible Indigenous communities in northern Saskatchewan to help improve the energy efficiency of new homes during construction.
- ⚡ **ACHIEVED** gold level status for the third consecutive time through the Canadian Council for Indigenous Business (CCIB) Partnership Accreditation in the Indigenous Relations (PAIR) program.
- ⚡ **ANNOUNCED** a project in 2024 that looked at creating new opportunities for more diverse suppliers — including local, Indigenous and women-owned businesses — to deliver the goods and services we need.
- ⚡ **SELECTED** as one of Canada's Best Diversity Employers, one of Canada's Top Employers for Young People, and one of Saskatchewan's Top Employers.

LETTER OF TRANSMITTAL



Regina, Saskatchewan
June 2025

Her Honour the Honourable Bernadette McIntyre, S.O.M.
Lieutenant Governor of Saskatchewan
Province of Saskatchewan

May it please Your Honour:

I have the honour to submit herewith the annual report of the Saskatchewan Power Corporation for the fiscal year ending March 31, 2025, in accordance with *The Power Corporation Act*.

The Financial Statements included in this annual report are in the form approved by Crown Investments Corporation of Saskatchewan, as required by *The Financial Administration Act, 1993* and have been reported on by the auditors.

Respectfully submitted,

A handwritten signature in black ink, appearing to read 'Jeremy Harrison'.

Honourable Jeremy Harrison
Minister Responsible for SaskPower

A MESSAGE TO OUR STAKEHOLDERS

Fulfilling our company's mission — to ensure reliable and affordable power for our customers and the communities we serve — is a commitment SaskPower never takes lightly. Regardless of the weather or time of day, our team of nearly 3,300 employees is committed to ensuring the power our customers rely on is always there when they need it.

Over the past 12 months, this resolve to serve customers was put to the test. In June 2024, employees near Carrot River rallied to support the northeastern Saskatchewan community after a destructive weekend storm severely impacted service for about 800 customers. Some of our crews remained in the area for weeks to repair damaged equipment. Meanwhile, in August 2024, the Flanagan fire came within a kilometre of our Island Falls Hydroelectric Station. While non-essential staff were evacuated, 12 employees volunteered to remain as the fire approached. Proactive responses — including fire suppression sprinklers on roofs of the station's multiple buildings — meant we could continue uninterrupted power generation during a challenging time.

The way we responded to these events highlights the importance of teamwork and proactive operational planning in SaskPower's day-to-day operations. Moving forward, both these traits will be essential as we secure Saskatchewan's energy future.

Planning is underway for development of nuclear power from small modular reactors (SMRs) in the province. We are in the midst of a multi-year process to complete the work required to make a final investment decision in 2029. In 2024, we established a new subsidiary called SaskNuclear to advance the SMR project through the regulatory and licensing process. Work on selection of a final site in the Estevan area is underway.

In the meantime, the natural gas-fired 370-megawatt (MW) Great Plains Power Station was officially opened in December 2024 and will help provide baseload generation for our electricity system. At the same time, to help maintain reliable service when electricity demand spikes over short periods of time, Saskatchewan's first 20-MW utility-scale battery energy storage system began operations in 2024. Located in Regina, this facility will also support intermittent power sources like wind and solar, including the new Bekevar Wind Power Facility. Having entered service in December 2024, the 200-MW facility is the largest operating wind power facility with Indigenous ownership in the province to date.

Other initiatives advanced in 2024-25 to modernize our province's electricity system include ongoing construction at the Aspen Power Station near Lanigan. This natural gas-fired facility is scheduled to begin generating 370-MW of power by the end of 2027. In addition, our first custom-built community microgrid came online in April 2025 and is providing power to the small northern community of Descharme Lake. The independent solar-battery-diesel combination microgrid is an innovative solution that will provide safe and reliable power for the community year-round and in all weather conditions.

In planning for the future electricity needs of our customers, maintaining a fleet of diversified power generation sources continues to be essential. During 2024, agreements for the 100-MW Iyuhána Solar Energy Project near Estevan and the 200-MW Seven Stars Wind Energy Project in the Weyburn area were finalized. Meanwhile, agreements signed with Steel Reef Infrastructure Corp. mean we can purchase up to 125 MW of natural gas-generated power from five sites in the province.

DELIVER IMPROVED VALUE FOR OUR CUSTOMERS AND STAKEHOLDERS

With a focus on finding solutions that make our customers' lives easier, SaskPower's website was updated during the past year to include an online self-serve form for starting, stopping or transferring power service. To better reflect a changing provincial population, our website now offers translation services in over 100 languages.

The Energy Efficiency Discounts Program — which had previously provided residential customers with instant savings on select energy efficiency purchases — was reintroduced in 2024 and expanded to include dishwashers, washing machines and home insulation. A new rebate program aimed at supporting new home construction in northern Indigenous communities was launched and is expected to deliver up to \$3,000 in annual power savings for each qualifying new build. For the second year in a row, a province-wide electric heat relief program provided \$2.1 million in relief to partially offset the cost of the federal carbon charge for customers who use electricity as their primary heating source during the winter.

Knowing that affordability issues are top of mind for our commercial customers, SaskPower began offering free consulting services and financial support through the Commercial Energy Optimization Program, which will help lower power bills and improve operational efficiency.

DEVELOP THE WORKFORCE TO MEET OUR FUTURE NEEDS

The safety of our employees is never taken for granted. After completing the multi-year Roadmap to Safety Program, we established a new Safety Leadership Council to actively solicit ideas from staff and contractors on ways we can improve the safe execution of all work.

We are proud to continue to record high levels of employee satisfaction in the workplace. In our biennial company-wide employee engagement survey, overall employee engagement was 72%, up 3% from 2022. SaskPower was honoured during the past 12 months to once again be recognized as one of Saskatchewan's Top Employers, as well as one of



Canada's Best Diversity Employers and Canada's Top Employers for Young People. Looking ahead, our multi-year Indigenous Recruitment and Retention Strategy, along with a new program launched in 2024, within which high school students can work alongside experienced powerline technicians over the summer, are two examples of the steps we are taking to attract new talent into our workforce.

ENSURE OUR FINANCIAL HEALTH

In 2024-25, SaskPower reported a consolidated net income of \$76 million. The decrease in net income, as compared to the previous year, was primarily due to a lower volume in exported electricity sales to Alberta and the Southwest Power Pool at lower average sales prices. Our balance sheet remained strong with a 76.2 per cent debt ratio.

BUILD A RELIABLE, SECURE AND AFFORDABLE ELECTRICITY SYSTEM FOR THE FUTURE

SaskPower spent nearly \$1.5 billion in 2024-25 to modernize, grow and sustain the provincial electricity system, which represented a \$284 million increase over the previous year. In downtown Regina, a multi-year infrastructure initiative underway will increase electrical capacity, improve reliability and enable our crews to find and fix outages faster through smart technology.

Meanwhile, about 21% of the smart meters that we plan to install as part of a province-wide deployment are now in service. Eventually,

smart meters will provide customers with more information about their power use and help reduce the duration of power outages. In October 2024, our carbon capture and storage (CCS) facility at Boundary Dam Power Station Unit 3 celebrated its 10-year anniversary. As the world's first large coal-fired power station to successfully use CCS technology, its grand opening in 2014 attracted international attention. Over a decade of operation, the facility has captured nearly seven million tonnes of carbon dioxide from being emitted into the atmosphere.

No matter where you live and work in Saskatchewan, electricity is an essential part of daily life. Across SaskPower, we value the trust that our customers place in us to deliver the energy they need. The road ahead for SaskPower must chart a course to meet the growing demand for power, maintain service reliability, and still ensure affordable rates. Through regular and meaningful engagement with our customers, we are confident in our ability to respond and power the province into a bright future.

Bryan Leverick
Acting Chair, Board of Directors

Rupen Pandya
President and CEO

MANAGEMENT'S DISCUSSION AND ANALYSIS

May 28, 2025

The following is a discussion of the consolidated financial condition and results of the operations of Saskatchewan Power Corporation (SaskPower; the Corporation) for the year ended March 31, 2025. It should be read in conjunction with the audited financial statements and accompanying notes. The financial information discussed herein has been prepared in accordance with International Financial Reporting Standards (IFRS).

This Management's Discussion and Analysis (MD&A) contains forward-looking statements based on the Corporation's estimates and assumptions concerning future results and events. Due to the risks and uncertainties inherent in any forecasted outlook, the actual results of the Corporation could differ materially from those anticipated. These risks and uncertainties include natural gas prices; coal and hydro availability; weather; economic conditions; number of customers; supply chain; and market conditions in other jurisdictions.

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OUR BUSINESS

At SaskPower, we are committed to supporting economic growth and enhancing the quality of life in Saskatchewan. At the foundation of our business strategy is the pursuit of our vision of powering Saskatchewan's energy future through innovation, performance and service. We work around the clock to provide power generation, transmission and distribution services to over 560,000 customer accounts. Our company prides itself on maintaining one of the largest service areas in Canada — a geographic region of approximately 652,000 square kilometres.

SaskPower is a vertically integrated utility with nearly 3,300 permanent full-time employees. Almost one-half of our workforce is composed of members of the International Brotherhood of Electrical Workers Local 2067. Approximately 13% of workers are members of Unifor Local 649, with out-of-scope staff accounting for the balance.

Our company manages nearly \$15 billion in assets, relying on generation sources that use a wide range of fuels that include natural gas, coal, hydro, wind and solar. This diversity provides a hedge against supply and price volatility, protecting customers from some of the risk inherent in any single fuel. SaskPower has two wholly owned subsidiaries — NorthPoint Energy Solutions and SaskNuclear Incorporated.

3,300

NUMBER OF PERMANENT FULL-TIME EMPLOYEES

MANDATE

SaskPower traces its origins to the Saskatchewan Power Commission that was founded in 1929. In 1949, our company was incorporated as a provincial Crown corporation under the authority and mandate of *The Power Corporation Act* (the Act). The Act has had a number of modifications over its lifetime. However, SaskPower's mission — ensuring reliable and affordable power for our customers and the communities we serve — has not fundamentally changed.

The Act grants SaskPower the exclusive franchise within the province of Saskatchewan (except for the City of Saskatoon and the City of Swift Current) to supply, transmit and distribute electricity, as well as to provide retail services to

customers. The reseller class of customers is restricted to two cities that retained their municipal franchises — the City of Saskatoon and the City of Swift Current.

SaskPower opened Saskatchewan's wholesale electricity market to competition through an open access transmission tariff (OATT) in 2001. It allows competitors to schedule access to our transmission system, enabling them to wheel power through Saskatchewan or sell to SaskPower's wholesale (reseller) customers.

Our company's vision, mission and values flow from the Act and SaskPower's relationship with our parent company, Crown Investments Corporation (CIC) of Saskatchewan. We support the strategic

direction provided by CIC. In turn, CIC is responsive to general government direction as articulated in a variety of ways, such as through the annual Speech from the Throne or formal policy statements.

Pursuant to the Act, the President and Chief Executive Officer of SaskPower reports to a Board of Directors appointed by the Lieutenant Governor in Council. Through the Chair, our company's Board of Directors is accountable to the Minister Responsible for SaskPower. The Minister functions as a link between SaskPower and provincial cabinet, as well as the Saskatchewan Legislative Assembly.

OUR CAPACITY TO DELIVER RESULTS

Since its creation in 1929, SaskPower has managed a system of generation, transmission and distribution assets that currently serve over half a million customers in Saskatchewan, through the provision of reliable and affordable power. In response to ongoing economic growth and a changing energy landscape, SaskPower is focused on projects and investments across Saskatchewan to modernize and grow the provincial electricity system so it can meet the needs of customers today and into the future, without compromising affordability of service.

SUPPLY AND NETWORK

SaskPower's total available generating capacity is 5,930 megawatts (MW). Power production facilities owned and operated by the company account for 4,241 MW of this capacity. The company's thermal generation fleet consists of eight natural gas-fired stations and three coal-fired stations. Seven hydroelectric stations and two wind power facilities also deliver electricity into the provincial grid.

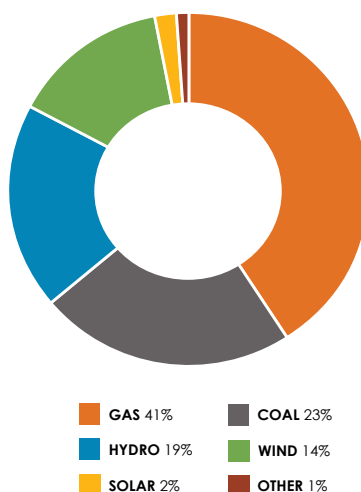
Additionally, SaskPower engages with large independent power producers (IPPs) to secure 1,580 MW of natural gas, hydro, solar and wind generation through power purchase agreements (PPAs). Another 73 MW of power is obtained through customer-generated solar power generation contracts, while 3 MW is obtained through customer-generated wind power generation agreements. Small IPPs that use waste heat recovery, flare gas, biomass and landfill gas generation technologies provide SaskPower with 33 MW of power.

To ensure service is not disrupted during planned SaskPower system maintenance or emergency repairs, the company maintains an operating reserve of 332 MW. This reserve also provides back-up power when intermittent sources of generation, such as wind or solar, are unable to produce power.

To manage electricity imports and exports, SaskPower relies on NorthPoint Energy Solutions Inc, a wholly owned subsidiary. When it can be sold for profit, surplus power is produced for export, while

electricity is imported into Saskatchewan in situations where it can be acquired at a price less than SaskPower's marginal cost of generation. Imports and exports flow through interconnections that the company maintains with neighbouring jurisdictions in Alberta, Manitoba and North Dakota.

2024-25 TOTAL AVAILABLE SYSTEM
GENERATING CAPACITY
5,930 NET MW



A network of provincial transmission and distribution assets moves electricity from generating stations to customers located across SaskPower's 652,000-square-kilometre (km) service area. To efficiently deliver large volumes of electricity (66,000 volts and above) to cities, towns or large industrial or commercial customers, the provincial transmission system deploys 14,816 circuit km of lines and

65 high voltage switching stations. These power voltages are stepped down before service is delivered to residential, farm, commercial and oilfield customers through a distribution system (less than 34,500 volts) that includes 144,868 circuit km of lines and 190,654 transformers.

SaskPower's provincial jurisdiction has a customer density relative to transmission and distribution infrastructure that is among the smallest of any utility in Canada. Generation facilities that are situated across the province pose an additional challenge. To deliver the reliable service our customers expect, 24/7 monitoring of provincial electricity system operations by employees at SaskPower's Grid Control Centre is paramount. A Supervisory Control and Data Acquisition (SCADA) system used by Grid Control Centre employees allows for remote operation and control of generation facilities.

During the fiscal year, SaskPower's capital spending totalled \$1.5 billion. Of that total expenditure, investments into the sustainment of existing provincial electrical infrastructure amounted to \$555 million. Meanwhile, investment in new generation facilities amounted to \$590 million and included the following projects: \$36 million for the Great Plains Power Station, \$420 million on the Aspen Power Station and \$130 million on plant expansions at the Ermine and Yellowhead Power Stations.

TOTAL 2024-25 CAPITAL EXPENDITURES **\$1.5B**

14.7 MW TOTAL CUSTOMER-INSTALLED POWER TO THE GRID THROUGH THE POWER GENERATION PARTNER PROGRAM SINCE IT LAUNCHED IN 2018

To connect new customers to the provincial grid, SaskPower spent \$192 million during the previous 12 months. Investment to increase capacity in both the transmission and distribution systems equalled \$73 million. Strategic and other investments during the year amounted to \$87 million. To help offset total capital costs, grant funding of \$74 million was applied.

OUTLOOK

As SaskPower plans for investments in the maintenance and expansion of a provincial energy system that will serve Saskatchewan for decades, we must also navigate a series of challenges: maintaining affordable rates for customers, improving service reliability, and responding to a growing demand for power. Our ability to map a viable path for the future relies, in large part, on continuing the meaningful two-way engagement SaskPower has established with customers, Indigenous Rights Holders, as well as business and industry stakeholders across the province.

CUSTOMER EXPERIENCE

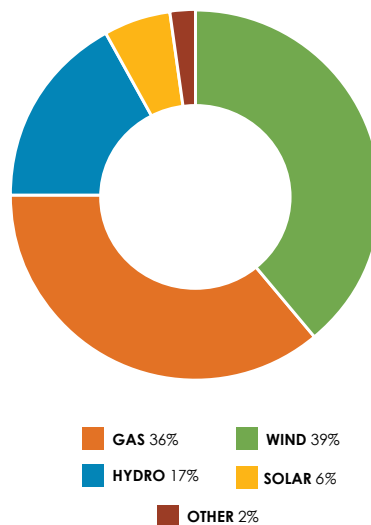
As we continually assess the evolving needs of those who rely on our services, the last 12 months saw SaskPower respond by implementing a range of customer experience enhancements.

Although internal research conducted with our three customer segments — residential, small & medium business, and key & major accounts — confirmed that customer experience quality remains strong, the importance of improved communication and information from SaskPower remains a priority for customers.

One effort implemented to make it easier for customers to interact with SaskPower is a new multilingual phone translation service that enables a customer, a SaskPower employee and a translator to

engage in a three-way conversation. Our website's live chat function has also been enhanced to provide real-time translation services, while a tool on saskpower.com offers translation services in over 100 languages.

**2024-25 AVAILABLE GENERATING CAPACITY
IPPs AND CUSTOMER GENERATION**
1,689 NET MW



Recognizing that affordability issues can be a concern for residential customers, we reintroduced the Energy Efficiency Discounts Program in 2024 to provide instant savings on select energy efficiency purchases. We also expanded the offering to include dishwashers, washing machines and home insulation. Meanwhile, SaskPower's Energy Assistance Program continued to deliver electrical savings through financial support for the installation of energy efficient products in nearly 6,700 low-income homes. Since the program launched, it has delivered almost \$1 million in power savings for customers.

Looking ahead, all provincial residents will soon benefit from the company's smart meter initiative. Approximately 21% of these smart meters have already been deployed across Saskatchewan for residential customers, which will ultimately provide more information about power

use, assist with reducing the duration of power outages, and eliminate the need to submit a manual power reading.

Through 2024, SaskPower continued to see strong uptake in programs for those who want to support renewable power. In the last year, approximately 450 new customers signed up for our Net Metering Program, through which participants can generate up to 100 kilowatts of power using an eligible energy resource to offset their own electricity use. Meanwhile, eligible customers participating in the Power Generation Partner Program have installed a total of 14.7 MW of renewable and environmentally preferred power to the grid since the program launched in 2018.

At the beginning of 2025, SaskPower launched the Renewable Subscription Service for small and medium business, farm and residential customers. This optional service offers customers the opportunity to purchase Renewable Energy Certificates generated from SaskPower's renewable generating facilities, a service which was previously only available to SaskPower's largest industrial customers.

SaskPower's commitment to forge stronger connections with Indigenous businesses, employees and communities was recognized this past year. For the third consecutive time, we achieved gold status through the Canadian Council for Indigenous Business (CCIB) Partnership Accreditation in Indigenous Relations (PAIR) program.

Meanwhile, the Northern First Nations Home Retrofit Program remains an important initiative to address high power bills for Indigenous customers. Since the program's launch in 2021, almost 600 homes have received energy efficiency assessments, with nearly 400 of them having had retrofits completed. In 2024, the program was expanded to include windows and doors, which increases the potential for power bill savings.

With the launch of the Indigenous New Homes Rebate Program during the past year, we now offer financial support for eligible Indigenous communities in northern Saskatchewan to improve the energy efficiency of new homes during construction. Resulting power savings are expected to be up to \$3,000 annually per new home build. The rebate will be supported by the Government of Canada's Future Electricity Fund which returns federal Output-Based Pricing System carbon pricing proceeds collected from Saskatchewan residents.

The introduction of the Commercial Energy Optimization Program (CEOP) in 2024 aligns with SaskPower's objective to be seen as a trusted advisor by large, medium, and small business customers. Based on the size and needs of a participating business, customized CEOP service offerings range from no-cost energy reduction strategies to free energy management coaching, as well as financial incentives for upgrading facilities with more efficient equipment.

A SUPPLIER FOCUS

Recognizing the role that SaskPower plays in supporting Saskatchewan's economic growth, fostering job creation, and promoting economic equity, our company launched a pilot project in 2024 that is creating new opportunities for more diverse suppliers — including local, Indigenous and women-owned businesses — to deliver the goods and services we need. As part of this pilot, prime contractors on SaskPower major construction projects are required to prioritize diverse and local suppliers in their subcontracting. To date, the initiative has resulted in \$132 million of work being directed toward Indigenous businesses, \$28 million directed toward women-owned businesses, and \$479 million toward local businesses.

SaskPower has a proud 10-year history of fostering Indigenous participation and capacity building in our supply chain. By embedding Indigenous content into our Requests for Proposals, our company promotes a more inclusive supply chain, while also significantly contributing to the professional and economic growth and development of Indigenous communities and people.

Launched this fiscal year, the Indigenous Capacity Building Initiative represents a new evaluation and supplier selection model, in which proponents share their methods and commitments to growing Indigenous capabilities through the work they deliver to SaskPower. Responses encompass recruitment, bursaries, scholarships, apprenticeships, sponsorships, donations, community investments, and skilled training programs aimed at building the local Indigenous workforce.

With 15.1% of total purchase orders issued to Saskatchewan suppliers in the last fiscal year directed to Indigenous suppliers, our company exceeded its targeted 11.0% of Saskatchewan purchase orders issued and registered our highest annual expenditure ever in this segment. Work at the 370-MW natural gas-fired Aspen Power Station near Lanigan played a key role in reaching this milestone and saw us make our largest-ever contract award to an Indigenous firm for construction at a natural gas facility.

To support all suppliers wanting to improve their success rate on SaskPower procurement opportunities, we continued to offer free supplier competitive bid training curriculum throughout the year. A specific focus on diverse supplier communities was the focus of our training efforts in 2024-25. Since the introduction of this curriculum, we have delivered 31 sessions and reached 406 companies, with 36% of those companies having diverse ownership.

FINANCIAL OUTLOOK

A consolidated net income of \$76 million was reported by SaskPower in 2024-25. The decrease in net income, as compared to the previous year, was primarily due to a lower volume of exported electricity sales to Alberta and the Southwest Power Pool at lower average sales prices. Our balance sheet remained strong with a 76.2 per cent debt ratio.

Effective April 1, 2025, SaskPower paused the collection of the federal carbon charge rate rider as mandated by the Government of Saskatchewan. Removing the federal carbon charge is anticipated to save the average residential customer approximately \$112 per year, while farms can expect to save around \$330 per year.

Meanwhile, SaskPower's electric heat relief program delivered \$2.1 million in savings to residential and farm customers who must rely on electric heat, through a 60% reduction in the federal carbon charge that was collected on their power bills between November 1, 2024, and March 31, 2025.

THE ELECTRICITY SYSTEM

SaskPower was active on a variety of fronts during 2024-25 as the company continues to renew and expand the provincial electricity system. Work to advance Saskatchewan's first nuclear small modular reactor (SMR) took an important step forward as a new corporate subsidiary — SaskNuclear — was established to help bring the SMR project through the regulatory and licensing processes. During the year, the search for a site for an SMR facility was narrowed to two locations near Estevan. As public engagement efforts continue, as well as technical and environmental evaluations of these short-listed locations, a final site selection is slated to be made by the end of 2025.

TOTAL PURCHASE ORDERS ISSUED TO SASKATCHEWAN SUPPLIERS
DIRECTED TO INDIGENOUS SUPPLIERS IN 2024-25

15.1%

2 LOCATIONS NEAR ESTEVAN BEING CONSIDERED AS A POTENTIAL SITE FOR A NEW NUCLEAR SMR

Maintaining diversity in our corporate generating fleet remains a key principle in the province's long-term energy strategy. The official opening of the natural gas-fired 370-MW Great Plains Power Station in December 2024 will help provide flexible baseload generation to our electricity system. At the same time, the 370-MW natural gas-fired Aspen Power Station, located near Lanigan, is on target to begin delivering power to the grid in 2027.

Other efforts to bolster the reliability and affordability of our electricity system in the last fiscal year included work to expand the Ermine and Yellowhead Power Stations, through the addition of a 46-MW simple cycle gas turbine at each facility. The projects are anticipated to be complete by the end of 2025. Meanwhile, agreements were signed with Steel Reef Infrastructure Corp. (Steel Reef) that will see SaskPower be able to purchase up to 25 MW of natural gas-generated power from each of Steel Reef's five gas processing sites in Saskatchewan beginning as early as 2027. Importantly, these sites are situated in the southeast and west central regions of the province, where demand for power continues to grow.

A key benefit with our fleet of natural gas-powered facilities is the reliable back-up power it provides for SaskPower's intermittent renewable generation facilities. At the end of 2024, the Bekevar Wind Power Facility entered operation, with an installed capacity of 200 MW. Bekevar is owned by a partnership that includes the largest Indigenous ownership of any operating wind facility in Saskatchewan.

During the year, SaskPower also finalized a PPA for the Seven Stars Wind Energy Project, a 200-MW wind facility planned

for the Weyburn area. The project involves a partnership between Enbridge Renewable Generation Inc. and Six Nations Energy Development LP. Six Nations is a newly created consortium of Cowessess First Nation, George Gordon First Nation, Kahkewistahaw First Nation, Métis Nation-Saskatchewan, Pasqua First Nation and White Bear First Nation. They will own at least 30% of the Seven Stars project once it begins operation.

As part of competitive procurements that were launched to select renewable generation for south-central Saskatchewan, two IPPs were selected in April 2025 to develop, build, own and operate a new 200-MW wind facility and a new 100-MW solar facility, both located in south-central Saskatchewan. Both IPPs — Rose Valley Wind Limited Partnership (LP) and Southern Springs Solar LP — are partnerships between Potentia Renewables Inc. and M-Squared Renewables LP. M-Squared Renewables LP is a partnership between Meadow Lake Tribal Council and Mistawasis Nēhiyawak First Nation and will own a majority 51% share of each project.

As we explore new and innovative energy solutions that address our unique operational requirements, we realized two important milestones over the past year. In July 2024, Saskatchewan's first utility-scale battery energy storage system was put into service. Situated in northeast Regina, this system can power 20 MW of load for up to one hour and will help us respond to short-term spikes in the demand for power, while also supporting wind and solar generation. Meanwhile, our first custom-built community microgrid came online in April 2025 and is providing power to the small northern community of Descherm Lake. The independent solar-battery-diesel combination microgrid will provide safe and reliable power for the community all year-round and in all weather conditions.

When it began operations in 2014, Unit 3 at our Boundary Dam Power Station became the first utility-scale project in the world to use carbon capture and storage (CCS) technology. In October 2024, this facility proudly celebrated its 10-year anniversary. Over the past decade, SaskPower's CCS facility has captured nearly seven million tonnes of carbon dioxide.



OUR ENTERPRISE-WIDE STRATEGIC CONTEXT

SaskPower's strategic direction includes our company's vision, mission, and values statements, as well as our corporate goals and key initiatives. Our vision reminds us of the ideals we are pursuing and what we want to achieve in years to come. Our mission tells us why our business exists and defines its unique purpose. Meanwhile, our values are the fundamental principles that guide and govern our behaviour.

Our planning, execution and performance measurement activities are built around four corporate goals. They are our company's foundation for success, and are the key result areas that ultimately form the basis of individual goal-setting. Each goal plays a prominent role in SaskPower's Business Plan, Performance Management Plan and Corporate Balanced Scorecard, which are updated annually. Input is provided by our employees, Executive, and Board of Directors.

SaskPower aligns with the strategic direction set by our shareholder, Crown Investments Corporation (CIC) of Saskatchewan, and the Government of Saskatchewan. CIC develops Crown Sector Strategic Priorities which provide an outlook that forms the cornerstone of Crown strategies. SaskPower also aligns to additional provincial government direction — such as the *Prairie Resilience* climate change strategy and *Saskatchewan's Growth Plan - The Next Decade of Growth 2020-2030*.

CORPORATE GOALS

- 1 DELIVER IMPROVED VALUE FOR OUR CUSTOMERS AND STAKEHOLDERS
- 2 DEVELOP THE WORKFORCE TO MEET OUR FUTURE NEEDS
- 3 ENSURE OUR FINANCIAL HEALTH
- 4 BUILD A RELIABLE, SECURE AND AFFORDABLE ELECTRICITY SYSTEM FOR THE FUTURE

VISION

Powering Saskatchewan's energy future through innovation, performance and service.

MISSION

Ensuring reliable and affordable power for our customers and the communities we serve.

VALUES

Safety, openness, collaboration and accountability.



PERFORMANCE MEASURES

FURTHER INFORMATION

Customer Experience Index (residential/small & medium business/key & major account)
Competitive rates (thermal utilities)
Partnership Accreditation in Indigenous Relations
New Connect Construction Index

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Employee engagement
Lost-Time Injury Frequency Rate
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Return on equity
Per cent debt ratio
OM&A per customer account vs. Saskatchewan Consumer Price Index
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Equivalent Availability Factor
Distribution SAIDI/SAIFI
Transmission SAIDI/SAIFI

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OUR PERFORMANCE MEASURES AND TARGETS

SaskPower's operational and financial performance is driven by our four corporate goals, which serve as a basis for achieving our mission and vision.

They are the foundation of our Corporate Balanced Scorecard, which provides the framework for our day-to-day work, creation of targets, measurement of organizational performance and execution of long-term planning.

The measures, targets and results associated with each of SaskPower's corporate goals are contained within this section.

SASKPOWER CORPORATE BALANCED SCORECARD				
	2023-24 actual	2024-25 target	2024-25 actual	2024-25 performance
DELIVER IMPROVED VALUE FOR OUR CUSTOMERS AND STAKEHOLDERS				
Customer Experience Index (%) (residential/small & medium business/key & major account)	68/70/80	69/71/80	68/71/85	●/●/●
Competitive rates (thermal utilities) (%)	76.5	≤ 100.0	87.0	●
Partnership Accreditation in Indigenous Relations (PAIR) (level)	●	Gold	Gold	●
New Connect Construction Index (%)	82.1	≥ 80.0	81.4	●
DEVELOP THE WORKFORCE TO MEET OUR FUTURE NEEDS				
Employee engagement ¹ (%)	●	70	72	●
Lost-Time Injury Frequency Rate (%)	0.50	0.58	0.23	●
Lost-Time Injury Severity Rate (%)	16.3	14.1	2.1	●
Indigenous people (%)	8.5	9.0	8.3	●
Persons with disabilities (%)	5.6	6.8	5.9	●
Visible minorities (%)	13.1	13.5	14.0	●
Women in underrepresented positions (%)	14.4	15.0	14.5	●
ENSURE OUR FINANCIAL HEALTH				
Return on equity (%)	6.7	6.6	2.6	●
Per cent debt ratio (%)	74.4	75.0	76.2	●
OM&A per customer account vs. Saskatchewan Consumer Price Index (% growth)	2.1	<3.6	3.6	●
Capital Cost Performance Index (%)/Schedule Performance Index (%)	89/83	80/80	90/95	●/●
Indigenous procurement (%)	10.8	11.0	15.1	●
Crown collaboration (%)	411	100	116	●
BUILD A RELIABLE, SECURE AND AFFORDABLE ELECTRICITY SYSTEM FOR THE FUTURE				
Equivalent Availability Factor (%)	86.9	≥ 85.0	84.7	●
Distribution SAIDI/SAIFI (hours/outages)	5.0/3.9	5.5/3.7	4.8/3.3	●/●
Transmission SAIDI/SAIFI (minutes/outages)	119/2.4	135/3.0	140/2.3	●/●
● ≥ 20% better than target ● on target ● did not meet target by < 20% ● did not meet target by ≥ 20%				
● Denotes that actual results or targets are not available for that time period. 1. The employee engagement metric is a biennial survey. 2. This measure is reported on a calendar-year basis.				

CORPORATE GOAL 1

DELIVER IMPROVED VALUE FOR OUR CUSTOMERS AND STAKEHOLDERS

OUR CUSTOMERS EXPECT IMPROVED SERVICES AND COMMUNICATION CHANNELS, WHILE NEW TECHNOLOGIES ARE ENABLING A GREATER CUSTOMER ROLE IN THE POWER SYSTEM. WE WILL ENGAGE OUR CUSTOMERS IN PLANNING FOR A MODERNIZED GRID AND WE WILL OFFER CHOICES AND OPTIONS THAT MEET THEIR INDIVIDUAL NEEDS. WE WILL HELP CUSTOMERS MANAGE THEIR ELECTRICITY CONSUMPTION AND PROVIDE VALUE AS A TRUSTED ADVISOR.

CUSTOMER EXPERIENCE INDEX (RESIDENTIAL/SMALL & MEDIUM BUSINESS/KEY & MAJOR ACCOUNT)

The Customer Experience Index measures customer perceptions on how well SaskPower delivers the experiences that are most likely to create and sustain loyalty. It allows our company to identify specific operational areas, practices, and brand equity attributes that impact customer experience the most. SaskPower conducts annual customer experience research for all three of our customer segments: residential customers; small & medium business customers; and key & major account customers. This research uses a framework that measures quality-based (effectiveness, ease, and emotion) and loyalty-based (retention, enrichment, and advocacy) drivers to identify and prioritize areas for improvement that our customers value most.

Residential customers comprise the largest portion of SaskPower's customer base.

Small & medium business customers include non-residential customers with annual electrical consumption less than five gigawatt-hours (GWh), i.e. 5,000,000 kilowatt-hours, across all accounts.

Key & major account customers include major account customers with annual electrical consumption between five and 20 GWh and key account customers with annual electrical consumption equal to 20 GWh or more.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	69/72/78	69/71/80	69/72/80	PY+1/PY+1/80	PY+1/PY+1/80	PY+1/PY+1/80	72/74/80
Actual	68/70/80	68/71/85					

PY Denotes prior year result.

SaskPower's residential customer score for 2024-25 of 68% was one percentage point below target and remained consistent with our scores for the last two years. Improvements were reported for this segment feeling valued as a customer and for SaskPower being easy with which to do business. Customers' sentiment about affordability continued to be a key theme for 2024-25. Customers are interested in information and programs to help them manage their electricity use and lower costs. Residential customers expect high-quality customer service through seamless interactions, and relevant and timely content in our communications. SaskPower has an opportunity to leverage new capabilities to engage customers in a more personalized and meaningful way.

Our company's small & medium business customer score of 71% achieved target for 2024-25, an improvement of one percentage point from our previous score. High-quality service; first contact resolution; reliable power; and low rates remain priorities for small & medium business customers. This segment reported positive increases in the effectiveness of doing business with SaskPower and feeling valued as a customer. Our small & medium business customers continue to report feeling the financial pressures of inflation and are looking to SaskPower to help them manage their electricity use and lower costs through programs and information.

Our key & major account customer score of 85% improved five percentage points over our 2024-25 target and 2023-24 score. Key & major account customers report improvements in the ease and effectiveness of doing business with SaskPower and an increase in the positive emotion rating. Feeling valued as a customer improved six percentage points for this customer segment. Key & major customers expect SaskPower to communicate its plans for the future and provide customers an opportunity for input on decisions that impact them. Key & major account customers are interested in collaboration and partnerships and seek innovative, reliable, and affordable service offerings that support their business objectives.

COMPETITIVE RATES (THERMAL UTILITIES)

Our company aims to ensure SaskPower's system average rates are less than or equal to the system average rates for customers served by Canadian utilities primarily dependent on thermal generation (i.e., using coal, natural gas, nuclear or oil). SaskPower uses the results released annually by Hydro-Québec in its national survey, *Comparison of Electricity Prices in Major North American Cities*, to compare our rates against other thermal utilities within Canada. The survey reports annual rate data in effect on April 1. Canadian thermal utility cities include: Regina, SK; Calgary, AB; Edmonton, AB; Toronto, ON; Ottawa, ON; Halifax, NS; Charlottetown, PEI; and Moncton, NB.

The ratio of SaskPower's average monthly net bills (before municipal surcharges and taxes) to the average of the monthly net bills for other Canadian thermal utilities is calculated based on the seven consumption levels selected for analysis by Hydro-Québec. The categories are composed of one residential consumption level, one small power consumption level, three medium power consumption levels, and two large power consumption levels. The average of these ratios, reported as a percentage, is used for assessment.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	≤100.0	≤ 100.0	≤100.0	≤100.0	≤100.0	≤100.0	≤100.0
Actual	76.5	87.0					

As at April 1, 2024, SaskPower's rates were, on average, 13.0% lower than the average rates of seven other Canadian thermal utilities across seven customer classes, a decline of more than 10 percentage points compared to the prior year, and well within target.

SaskPower's rates were lower than thermal averages in all seven customer categories, with our rates ranking the lowest in the two large power classes and two medium power classes. SaskPower's rate for the residential class — the class which has historically been above the thermal average — has now been below average for two consecutive years.

PARTNERSHIP ACCREDITATION IN INDIGENOUS RELATIONS (PAIR)

The Canadian Council for Indigenous Business (CCIB) Partnership Accreditation in Indigenous Relations (PAIR) certification program confirms corporate excellence in Indigenous relations. Gold status recognizes businesses that demonstrate well-integrated, mature business processes in leadership action, employment, business development, and community relationships.

SaskPower's PAIR certification at the Gold status level was achieved in 2017 and renewed by the CCIB in 2020. Our company remains committed to cultivating strong, mutually beneficial relationships with Indigenous peoples, communities and businesses.

(status level)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	●	Gold ¹	●	●	Gold	●	Gold
Actual	●	Gold					

● Denotes that actual results or targets are not available for that time period.
1. Effective 2024-25, the reporting period for this measure transitioned from the third year reviewed to the year of announcement.

SaskPower met its 2024-25 target and achieved gold status through the CCIB PAIR program for the third consecutive time.

The process to certify within the PAIR program is extensive, with CCIB basing its decision on three years of reporting which must provide sufficient evidence of the work completed and include documented corroboration and demonstration of actions.

SaskPower's final report noted several initiatives that supported our company's gold status recertification, including:

- Strong leadership commitment to Indigenous relations;
- Mandatory Indigenous Cultural Awareness training;
- Implementation of the Indigenous Customer Care program, the first of its kind in Canada;
- Strong community engagement practices to obtain feedback from communities on their priorities;
- Indigenous procurement targets (in 2023, SaskPower awarded 15.5%, or \$94.1 million, in contracts to Indigenous suppliers);
- Robust Indigenous recruitment and retention; and
- Strong communication within the company and communities.

NEW CONNECT CONSTRUCTION INDEX

The New Connect Construction Index measures the percentage of new connect orders that SaskPower completes before the later of the customer’s specified need date and the associated cycle-time target for the type of order.

Prepaid notifications have a targeted cycle time of 10 days, starting from the time a request is made or the customer indicates the site is ready, whichever is later (i.e. SaskPower/SaskEnergy/SaskTel Joint Service initiatives).

Non-complex service orders have a targeted cycle time of 45 days from customer quote acceptance (i.e. any order that is not categorized as complex).

Complex service orders have a targeted cycle time of 90 days from customer quote acceptance (i.e. service extension length greater than 800 meters; main distribution in residential and commercial subdivisions; transmission line alterations; large load sizes; etc.).

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	≥ 80.0	≥ 80.0	≥ 80.0	≥ 80.0	≥ 80.0	≥ 80.0	≥ 80.0
Actual	82.1	81.4					

Our company’s New Connect Construction Index performance for 2024-25 of 81.4% surpassed our target of 80.0%. SaskPower experienced a 2.8% increase in the total volume of new connect requests completed during the year, with increases in both non-complex and prepaid service order volumes. SaskPower’s performance in this metric continues to demonstrate our ongoing efforts to meet higher customer expectations while balancing resource allocation against system maintenance and capital sustainment programs.



CORPORATE GOAL 2

DEVELOP THE WORKFORCE TO MEET OUR FUTURE NEEDS

OPERATING THE MODERN POWER SYSTEM OF TOMORROW WILL REQUIRE A WORKFORCE WITH NEW SKILLS. THE FINANCIAL PRESSURES OF TODAY NECESSITATE A CULTURE IN WHICH EVERY EMPLOYEE IS ACCOUNTABLE FOR DRIVING EFFICIENCY AND PERFORMANCE IMPROVEMENT, WITHOUT COMPROMISING ON SAFETY OR CUSTOMER EXPERIENCE. WE WILL ENSURE OUR WORKFORCE IS HIGH PERFORMING, ENGAGED, AND AS DIVERSE AS THE COMMUNITIES WE SERVE.

EMPLOYEE ENGAGEMENT

SaskPower wants to ensure it has engaged employees while creating an environment of accountability and high performance. Employee engagement is defined as an emotional and intellectual connection that employees have for their job, organization, manager, and coworkers that, in turn, influences them to apply additional discretionary effort to their work. This biennial metric identifies the percentage of employees that have a favourable level of engagement.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	•	70	•	73	•	73	73
Actual	•	72					

• Denotes that actual results or targets are not available for that time period.

SaskPower conducted its biennial employee engagement survey in September 2024 and based on a response rate of 80%, received an overall engagement score of 72%. This score represents an improvement of two percentage points over our target, three percentage points over our previous results in 2022-23, and one percentage point above the large commercial average against which SaskPower is benchmarked. Our scores improved in all of the six areas of organizational engagement relative to the previous survey.

Notable improvements in overall dimension scores from the previous survey were reported for senior leadership (12%), work/life balance (7%), Innovation (6%), satisfaction (5%), and organizational culture (5%).

LOST-TIME INJURY FREQUENCY RATE

Lost-time Injury Frequency Rate (LTIFR) refers to the occurrence rate of workplace incidents that result in an employee missing time from work after the date of the injury, per 100 workers. LTIFR also refers to the number of such injuries that occur within a given period relative to the total number of hours worked in the same reporting period.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	0.55	0.58	0.55	0.52	0.49	0.47	0.43
Actual	0.50	0.23					

SaskPower's LTIFR of 0.23 performed better than our 2024-25 target of 0.58, and the overall total number of lost time incidents that occurred dropped from 16 in the previous year to nine in 2024-25. The strong performance in this indicator is a positive indication of the effectiveness of our safety strategies and ongoing efforts to enhance our safety culture.

LOST-TIME INJURY SEVERITY RATE

Lost-time Injury Severity Rate (LTISR) is the number of lost workdays experienced per 100 workers. LTISR shows the extent of safety anomalies by revealing how critical the injuries and illnesses are. The theory is that an employee who takes time to return to work after injury had a more severe incident than an employee who can return immediately.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	14.1	14.1	14.1	13.4	12.7	12.1	10.9
Actual	16.3	2.1					

The 2024-25 LTISR result of 2.1 outperformed our target of 14.1 lost workdays by 85%. The nine lost-time injuries as at March 31, 2025, resulted in a total of 81 calendar days lost, a significant improvement from the 519 calendar days lost in the prior year.

Safety remains a top priority for SaskPower, as we continue to improve our safety culture through initiatives such as the Safety Mentorship Program and the Safety Leadership Council.

INDIGENOUS PEOPLE

Indigenous people measures the percentage of SaskPower's permanent employees who self-identify as Indigenous through our company's self-declaration process.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	•	9.0	8.8	PY +0.5	PY +0.5	PY +0.5	15.2
Actual	8.5	8.3					

• Denotes that actual results or targets are not available for that time period.
PY Denotes prior year result.

In 2024-25, 8.3% of SaskPower's workforce had self-declared as Indigenous people, falling short of our target of 9.0%. While the number of permanent employees that self-identified as Indigenous increased compared to the prior year, growth of 0.3% in this equity grouped trailed behind the 1.8% growth in permanent employees.

To improve our recruitment and attraction of Indigenous talent, SaskPower developed an Indigenous Mentorship Program to enable our Indigenous employees to connect directly with Indigenous leaders to seek guidance and support related to Indigenous ways of living and working.

PERSONS WITH DISABILITIES

Persons with disabilities measures the percentage of SaskPower's permanent employees who self-identify as having a disability through our company's self-declaration process.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	•	6.8	6.4	PY +0.5	PY +0.5	PY +0.5	27.7
Actual	5.6	5.9					

• Denotes that actual results or targets are not available for that time period.
PY Denotes prior year result.

As at March 31, 2025, 5.9% of SaskPower's permanent workforce had self-declared as persons with a disability, falling below our target of 6.8%. Compared to 2023-24, an additional 14 employees self-identified as having a disability, a 7.2% increase in this equity group.

In compliance with *The Accessible Saskatchewan Act* which came into force in December 2023, SaskPower has developed an Accessibility Plan to identify, remove and prevent accessibility barriers for people with disabilities, enabling their full participation and contribution at work and in their communities. SaskPower's Accessibility Plan was made public in April 2025.

VISIBLE MINORITIES

Visible minorities measures the percentage of SaskPower’s permanent employees who self-identify as visible minorities through our company’s self-declaration process.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	●	13.5	14.5	PY +0.5	PY +0.5	PY +0.5	21.5
Actual	13.1	14.0					

● Denotes that actual results or targets are not available for that time period.
PY Denotes prior year result.

As at March 31, 2025, 14.0% of SaskPower’s permanent workforce had self-declared as a visible minority, surpassing our target of 13.5%. Compared to the previous year, 39 additional employees self-identified as a visible minority, an 8.6% increase in this equity group.

SaskPower’s Unconscious Bias e-learning module has been completed by of 94.0% of our workforce, while 94.5% of hiring managers have completed our company’s Managing Bias in Hiring workshop.

WOMEN IN UNDERREPRESENTED POSITIONS

Women in underrepresented occupations measures the percentage of women in permanent positions or occupations identified as having less than 47.5% representation as at April 1, 2024.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	●	15.0	15.3	PY +0.75	PY +0.75	PY +0.75	47.5
Actual	14.4	14.5					

● Denotes that actual results or targets are not available for that time period.
PY Denotes prior year result.

The women in underrepresented occupations metric as at March 31, 2025, was 14.5%, below our 2024-25 target of 15.0%. Compared to 2023-24, an additional 14 women were in positions in which this equity group was underrepresented. This equates to 2.8% year-over-year growth.

SaskPower continues to provide support to female employees in skilled trade roles through the Advancing Women in Skilled Trades initiative. Our company also continues to promote and expand its Women’s Mentoring Circles, which provide the opportunity for out-of-scope female employees to be mentored by female leaders and network with other women aspiring to leadership roles.



CORPORATE GOAL 3

ENSURE OUR FINANCIAL HEALTH

THE ABILITY TO PRESERVE OUR FINANCIAL STRENGTH IS CRITICAL. CONTINUED INVESTMENT IN INFRASTRUCTURE WILL BE NEEDED TO MAINTAIN OR IMPROVE CURRENT LEVELS OF RELIABILITY AND ALSO TO MEET THE DEMAND FOR ELECTRICITY. ASSET OPTIMIZATION AND EFFICIENCY PROGRAMS WILL BE USED TO CONTINUALLY IMPROVE OUR BUSINESS PROCESSES AND REDUCE COSTS SO THAT WE MAINTAIN COMPETITIVE RATES.

RETURN ON EQUITY

Return on equity (ROE) measures SaskPower's financial performance, and is calculated as net income expressed as a percentage of average equity.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	0.8	6.6	8.5	8.5	8.5	8.5	8.5
Actual	6.7	2.6					

SaskPower's recorded ROE of 2.6% for the year ended March 31, 2025, was four percentage points below the 6.6% target. Net income was \$116 million below budget driven by decreased export revenue and Saskatchewan electricity sales. Export revenues were impacted by increased supply and new regulations in Alberta, which caused a significant drop in market prices. Meanwhile, export volumes were also down as the transmission intertie connecting Alberta and Saskatchewan was unavailable for most of the second half of the year due to a failure on Alberta's portion of the line. Mild weather throughout 2024-25 resulted in lower demand for electricity in all customer classes during the year compared to budget.

Net income results are explained in further detail in the financial results section of the Management's Discussion and Analysis.

PER CENT DEBT RATIO

The per cent debt ratio provides a measure of SaskPower's debt expressed as a percentage of the company's total corporate financing structure, composed of the total investment by creditors (debt) and the total investment of owners (equity). The extent to which a company is leveraged is directly correlated to the proportion of its capital structure that is comprised of debt. A highly leveraged company is considered to have less financial flexibility and more risk than a less leveraged company.

As SaskPower continues to modernize and expand its infrastructure, debt levels will increase in order to finance our capital program.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	75.4	75.0	TBD	TBD	TBD	TBD	60.0-75.0
Actual	74.4	76.2					

Our company's per cent debt ratio of 76.2% at March 31, 2025, was 1.2 percentage points over our target of 75.0%. This is primarily due to decreased closing equity arising from SaskPower's net income of \$76 million, which was \$116 million below budget for the year.

OM&A PER CUSTOMER ACCOUNT VS. SASKATCHEWAN CONSUMER PRICE INDEX



The operating, maintenance and administration (OM&A) per customer account versus the Saskatchewan Consumer Price Index (SK CPI) measure compares the growth of SaskPower's OM&A expense per customer account against the growth of the SK CPI to assess how efficiently our OM&A expense is being managed.

(% growth)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	3.2	<3.6	< SK CPI increase	< SK CPI increase	< SK CPI increase	< SK CPI increase	< SK CPI increase
Actual	2.1	3.6					

In 2024-25, SaskPower's five-year average annual growth in OM&A expense per customer account was 3.6%. Equivalent to the five-year average annual growth in the SK CPI over the same period, this result is just short of our target of managing expense growth below Saskatchewan's rate of inflation.

OM&A expense increased approximately \$54 million to \$865 million in 2024-25, driven by higher overhaul costs at our generation facilities and increased transmission maintenance activities. While OM&A costs exceeded budget for 2024-25, the average growth rate of SaskPower's OM&A expense per customer account has remained consistent with provincial inflation rates.

CAPITAL COST PERFORMANCE INDEX/SCHEDULE PERFORMANCE INDEX



SaskPower uses the Capital Cost Performance and Capital Schedule Performance Indices to evaluate our company's ability to manage large capital projects within approved budgets and schedules. These measures track the performance of capital projects with a minimum approved project budget of \$20 million. Each project included in this measure is weighted by its assessed project tier, which takes into account factors such as project size, complexity, and risk.

Capital Cost Performance Index (CPI) reports the percentage of projects for which actual expenditures have been managed within the project's budgeted cash flow at any point in time.

Capital Schedule Performance Index (SPI) reports the percentage of projects that have been kept on schedule by measuring a project's actual progress completed against the progress expected to be completed at any point in time.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	80/80	80/80	81/81	82/82	83/83	84/84	85/85
Actual	89/83	90/95					

SaskPower's CPI performance as at March 31, 2025, of 90% exceeded our annual target. Of the 17 large capital projects SaskPower invested in during 2024-25, 15 were successfully managed within or below budget as at year-end.

Our company's SPI result of 95% exceeded our target of 80%, with 16 of the 17 large capital projects managed on or ahead of schedule as at March 31, 2025.



INDIGENOUS PROCUREMENT

Our company is committed to promoting and pursuing viable business development opportunities through long-term relationships with Indigenous Rights Holders, communities and companies in the Province of Saskatchewan. The Indigenous procurement measure tracks the extent to which SaskPower engages in Saskatchewan Indigenous-sourced procurement relative to total Saskatchewan-sourced procurement.

(% ending 2024-25; \$ beginning 2025-26)	2023-24	2024-25	2025-26 ¹	2026-27	2027-28	2028-29	Long-term
Target	10.0%	11.0%	\$96 million	\$97 million	\$98 million	\$99 million	\$1 billion over 10 years
Actual	10.8%	15.1%					

1. Beginning in 2025-26, the Indigenous procurement measure will transition from being measured as a percentage of Saskatchewan procurement to targeting a specific dollar value.

SaskPower's Indigenous procurement accounted for 15.1% of the purchase orders issued to Saskatchewan suppliers, exceeding the target of 11.0% for the year. The majority of 2024-25 Indigenous contracts were for vegetation management services; engineering services; inventory items; and distribution construction work.

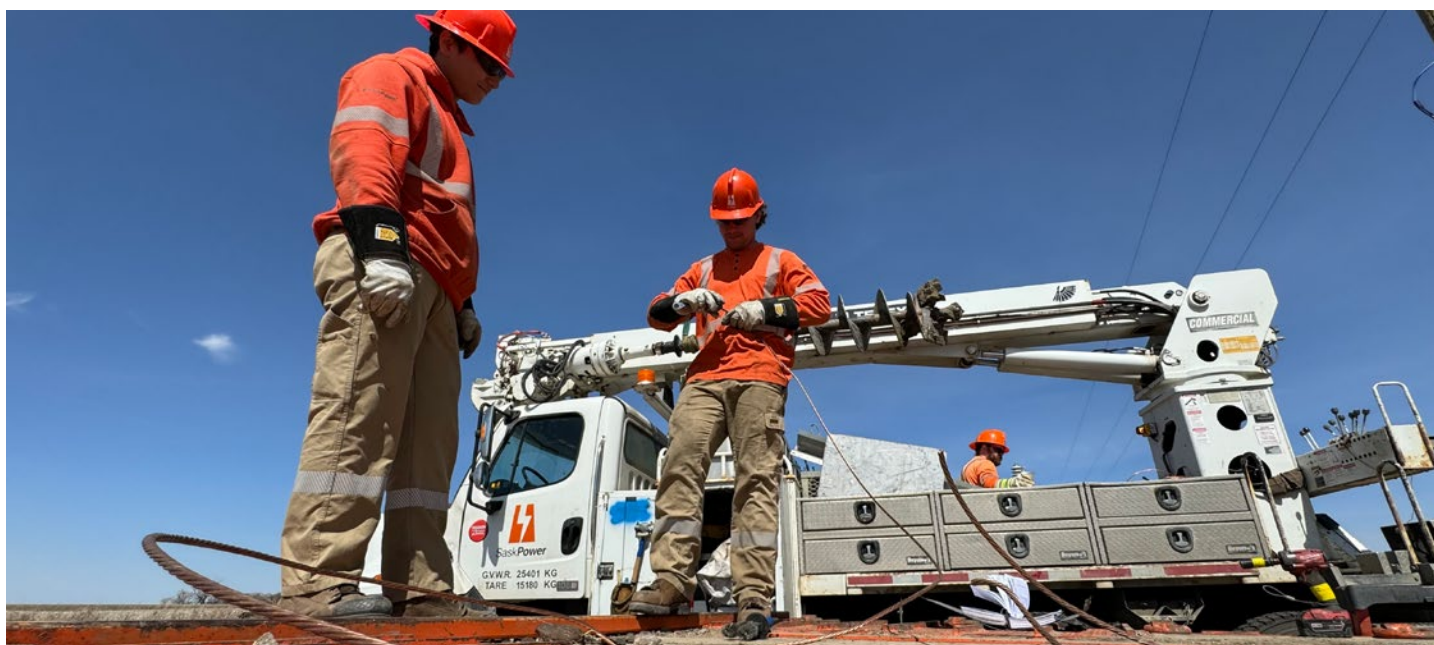
Our company's consistent efforts and dedicated focus to ensure that Indigenous vendors have ample opportunity to work with SaskPower is demonstrated with our total Indigenous procurement of \$118 million in 2024-25, up from \$95 million in 2023-24. This is the fourth consecutive year SaskPower has exceeded targeted spending levels, highlighting SaskPower's commitment to supporting Indigenous businesses and economic reconciliation.

CROWN COLLABORATION

The Crown collaboration measure is an index that tracks Crown sector performance based on equal weighting for two components: combined cost savings for Crown corporations and participating Treasury Board Crowns, agencies and ministries achieved through joint initiatives and collaboration efforts (50%) and private sector investments secured by the Investment Attraction Working Group (50%).

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	100	100	100	100	100	100	100
Actual	411	116					

Crown collaboration exceeded target, with a score of 116% for the year ended March 31, 2025. This favourable performance was lead by significant investments secured through the Investment Attraction Working Group. SaskPower continues to realize substantial savings through Crown collaboration initiatives, which include centralizing line locating services; joint workforce management software; joint infrastructure installation partnerships; new connect joint services; and centralizing project management for industrial customers. Our company's Crown collaboration efforts achieved savings that were 12% higher than the target planned for SaskPower.



CORPORATE GOAL 4

BUILD A RELIABLE, SECURE AND AFFORDABLE ELECTRICITY SYSTEM FOR THE FUTURE

WE ARE COMMITTED TO OPERATING A DIVERSE GENERATION FLEET TO MEET OUR CUSTOMERS' NEEDS, WHILE WELCOMING COLLABORATION WITH OUR CUSTOMERS AND COMMUNITIES ON ELECTRICITY OPTIONS. WE WILL ALSO USE AUTOMATION TO IMPROVE RELIABILITY AND GRID SECURITY.

EQUIVALENT AVAILABILITY FACTOR

The Equivalent Availability Factor (EAF) indicates the percentage of time that a generating unit is available for producing electricity, adjusted for any temporary reductions in generating capability due to equipment failures, planned maintenance, derates, or other causes. Consistent with standards from the Institute of Electrical and Electronics Engineers (IEEE) as well as guidance from the North American Electric Reliability Corporation (NERC), events outside of management's control (OMC) — such as severe weather beyond which infrastructure was built to withstand — are excluded.

In addition to determining the EAF for each SaskPower-owned generation unit, our company also consolidates this measure across our entire portfolio of generation assets, weighting each generation unit by its respective nameplate capacity. While higher EAF percentages are more favourable, targets are set giving consideration to prudent equipment maintenance and capital requirements.

(%)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	≥ 85.0	≥ 85.0	≥ 85.0	≥ 85.0	≥ 85.0	≥ 85.0	≥ 85.0
Actual	86.9	84.7					

SaskPower's overall weighted EAF performance of 84.7% in 2024-25 fell short of the annual minimum target of 85.0%.

Coal-fired generation had the lowest availability in 2024-25. The planned 32-day minor overhaul at Boundary Dam Power Station Unit 6 was extended an additional 36 days due to issues experienced with turbine and generator bearings. Meanwhile, availability for both Poplar River Power Station and Shand Power Station exceeded their respective targets.

Forced outages also occurred at natural gas-fired Great Plains Power Station — Unit 2 was offline for 17 days due to a steam leak, Unit 1 was offline for 11 days to repair a plugged spray valve, and both units were down a few days to replace gaskets. Queen Elizabeth Power Station, Chinook Power Station, and Cory Cogeneration Station had increased availability for the year.

Wind generation availability exceed its 2024-25 target while hydro generation was just shy of target for the year.

DISTRIBUTION SAIDI/SAIFI



SaskPower measures the reliability of its distribution system by using two industry-standard measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). While the results for these measures reflect both planned and forced outages, Major Event Days (MEDs) — which are defined as events that exceed reasonable infrastructure design and/or operational limits, as set out by the Institute of Electrical and Electronics Engineers (IEEE) — are excluded.

Distribution SAIDI allows us to track our company's performance of restoring service in response to outages. It is a measure of the service interruption length, in hours, that customers experience, on average, in a 12-month period. The distribution SAIDI results are impacted by a number of factors, including adverse weather during restoration; equipment condition; extent of outage; travel time to the trouble point; and line staff availability, familiarity with facilities and level of experience.

Distribution SAIFI reports the number of outages that customers experience, on an average, in a given year. This measure includes both controllable interruptions (outages from infrastructure failures, tree contacts, and scheduled outages) and uncontrollable interruptions (caused by elements such as adverse weather or the loss of transmission supply).

(hours/outages)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	5.9/2.9	5.5/3.7	5.1/3.5	5.1/3.5	5.0/3.3	5.0/3.0	3.8/2.3
Actual	5.0/3.9	4.8/3.3					

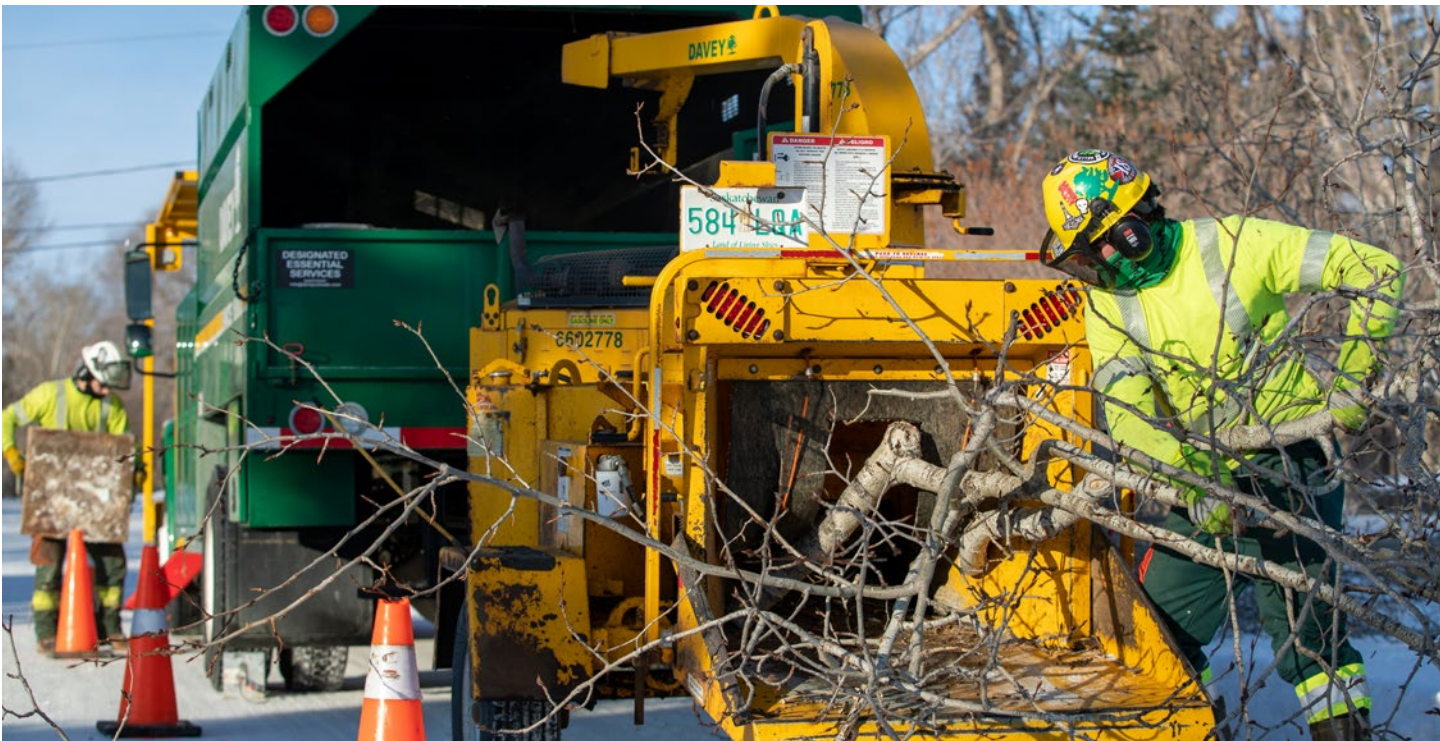
For 2024-25, SaskPower's distribution SAIDI performance of 4.8 hours outperformed both our annual target and the prior year result. The leading causes of distribution outage duration included the loss of transmission supply (31%), planned outages (17%), and faulty equipment (14%).

Our company's distribution SAIFI result of 3.3 outages per customer also outperformed our target of 3.7 outages. Loss of transmission supply was the largest contributor to distribution outages experienced (50%), followed by planned outages (11%), and faulty equipment (10%).

There was a single MED experienced by our distribution infrastructure during the year — down from two MEDs in the previous year — which has been excluded from our distribution SAIDI and SAIFI results:

- June 22, 2024: Six substations north of Prince Albert near Timber Cove and Willow Island were impacted by a 10-hour loss of transmission supply, resulting in over 139,000 total customer outage hours.

SaskPower's ongoing grid modernization efforts continue to improve outage reporting accuracy. As a result, our Distribution Control Office is recording a greater number of distribution outages caused by the loss of transmission supply. The same impact is not seen in the average distribution outage duration given the short outages typically caused by loss of transmission supply.



TRANSMISSION SAIDI/SAIFI



SaskPower also monitors the reliability of its transmission system using SAIDI and SAIFI measures, excluding Major Event Days (MEDs).

Transmission SAIDI tracks our performance restoring service in response to outages specific to our transmission assets. It reports the average forced interruption length, in minutes, experienced at a bulk electric service delivery point (BES DP) in one year. Transmission SAIDI is influenced by factors such as adverse weather and defective equipment.

Transmission SAIFI reports the average number of forced interruptions experienced at a given BES DP over a 12-month period. Forced interruptions include outages caused by weather conditions; defective equipment; system conditions like over-voltage; human element; and foreign interference such as wildlife contacts.

(minutes/outages)	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Long-term
Target	135/3.0	135/3.0	135/3.0	130/2.9	130/2.9	130/2.9	120/2.8
Actual	119/2.4	140/2.3					

SaskPower's transmission SAIDI performance of 140 minutes per BES DP was five minutes longer than our target of 135 minutes. The primary causes of transmission outage duration this year were defective equipment (63%), as well as adverse weather and environmental conditions (25%).

Our company's transmission SAIFI result of 2.3 outages outperformed our target of 3.0 outages. The largest number of transmission interruptions continued to occur due to adverse weather and environmental conditions (49%). Other leading causes of interruptions included defective equipment (19%), foreign interference (5%), and system configuration (5%).

There were two MEDs experienced by our transmission infrastructure during the year — compared to no MEDs in the previous year — which have been excluded from our transmission SAIDI and SAIFI results:

- September 3, 2024: Northern wildfires damaged three transmission lines, causing multiple outages and resulting in 15 structures collapsing. A total of 31 delivery point outages occurred, with a cumulative outage duration of 12,755 minutes.
- March 14, 2025: Freezing rain and snow in southern Saskatchewan led to galloping conductors on four transmission lines (72-kV Regina to Condie line, 72-kV Auburnton to Boundary Dam line, 138-kV Boundary Dam line to Steelman line, and Regina to Condie line), caused 31 delivery point outages with a combined outage duration of 4,776 minutes.



2024-25 FINANCIAL RESULTS

AT A GLANCE		
Revenue	\$	3,254M
Net income	\$	76M
Return on equity ¹		2.6%
Saskatchewan electricity sales		23,984 GWh
Gross electricity supplied		26,174 GWh
Property, plant and equipment	\$	12,294M
Total capital expenditures	\$	1,497M
Total net debt	\$	9,280M
Per cent debt ratio		76.2%
Customer accounts		562,232
Annual peak load (net MW)		3,838 MW

(in millions)	2024-25	2023-24	Change
Revenue			
Saskatchewan electricity sales	\$ 3,110	\$ 3,096	\$ 14
Exports	28	129	(101)
Other revenue	116	154	(38)
Total revenue	3,254	3,379	(125)
Expense			
Fuel and purchased power	1,105	1,240	(135)
Operating, maintenance and administration	865	811	54
Depreciation and amortization	638	605	33
Finance charges	418	409	9
Taxes	100	92	8
Other expenses	52	38	14
Total expense	3,178	3,195	(17)
Net income	\$ 76	\$ 184	\$ (108)
Return on equity¹	2.6%	6.7%	(4.1%)

1. Return on equity = (net income)/(average equity), where equity = (retained earnings + equity advances).

HIGHLIGHTS AND SUMMARY OF RESULTS

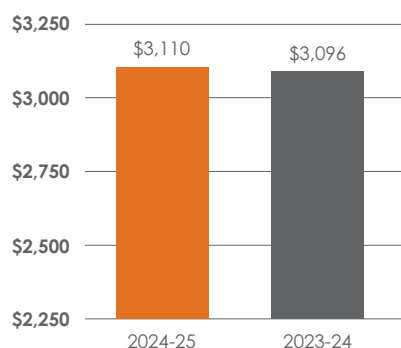
SaskPower reported a consolidated net income of \$76 million in 2024-25, compared to \$184 million in 2023-24. The \$108 million decrease was primarily due to a \$125 million decrease in revenue, partially offset by a \$17 million decrease in expense. The return on equity was 2.6%, down over four percentage points from the previous year.

Total revenue was \$3,254 million, compared to \$3,379 million in 2023-24. The \$125 million decrease in revenue was mainly attributable to a \$101 million decrease in exports due to lower sales volumes to Alberta and the Southwest Power Pool at lower average sale prices. In addition, other revenue decreased \$38 million due to lower customer contributions and carbon dioxide (CO₂) sales. These decreases were partially offset by a \$14 million increase in Saskatchewan electricity sales primarily due to higher carbon charges collected as a result of the 0.5% and 2.9% rate rider increases.

Total expense was \$3,178 million, down \$17 million from 2023-24. The decrease in total expense was mainly attributable to lower fuel and purchased power costs which decreased \$135 million primarily as a result of Clean Electricity Transition Grant funding received from the province. This decrease was partially offset by a \$54 million increase in operating, maintenance and administration (OM&A) expense attributable to increased maintenance at our generation facilities due to the timing of overhaul activities and higher planned maintenance costs on our transmission infrastructure. In addition, capital-related expenses — depreciation, finance charges, taxes and other expenses — increased a combined total of \$64 million. This was due to higher depreciation expense as a result of new capital additions as well as higher interest on long-term borrowings; higher corporate capital tax; and higher adjustments related to inventory and decommissioning provisions.

SASKATCHEWAN ELECTRICITY SALES

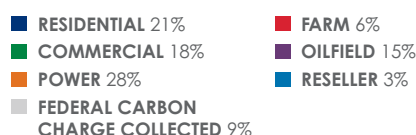
Saskatchewan electricity sales represent the sale of electricity to all customer classes within the province. These sales are subject to the effects of general economic conditions, number of customers, weather, and electricity rates. Included in Saskatchewan electricity sales is the federal carbon charge which is being recovered by SaskPower from its customers through a rate rider. The revenue associated with the federal carbon charge is set aside and used to fund the federal carbon tax payments.



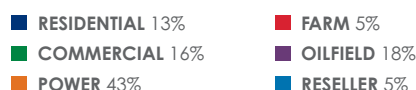
SASKATCHEWAN ELECTRICITY SALES (MILLIONS)



SASKATCHEWAN ELECTRICITY SALES - \$3,110 MILLION



ELECTRICITY SALES VOLUMES - 23,984 GWH



(in millions)	2024-25	2023-24	Change
Residential	\$ 637	\$ 632	\$ 5
Farm	188	198	(10)
Commercial	557	557	-
Oilfield	477	469	8
Power	879	895	(16)
Reseller	104	105	(1)
	2,842	2,856	(14)
Federal carbon charge collected	268	240	28
Saskatchewan electricity sales	\$ 3,110	\$ 3,096	\$ 14

(in GWh)	2024-25	2023-24	Change
Residential	3,248	3,224	24
Farm	1,226	1,305	(79)
Commercial	3,744	3,749	(5)
Oilfield	4,395	4,320	75
Power	10,228	10,531	(303)
Reseller	1,143	1,150	(7)
Electricity sales volumes	23,984	24,279	(295)

Saskatchewan electricity sales, excluding the federal carbon charge collected, were \$2,842 million in 2024-25, down \$14 million from 2023-24. Electricity sales volumes to Saskatchewan customers were 23,984 gigawatt hours (GWh), down 295 GWh or 1.2% compared to the prior year. The largest decline in electricity sales occurred in the power customer class. Consumption in the power customer class decreased 303 GWh, primarily due to decreased activity in the pipeline sector.

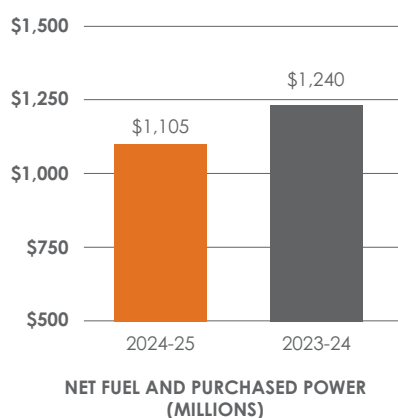
The federal carbon charge collected increased \$28 million compared to 2023-24, mainly due to the 0.5% and 2.9% rate rider increases effective January 1, 2024, and 2025, respectively.

SaskPower paused collection of the federal carbon charge rate rider effective April 1, 2025, as mandated by the Government of Saskatchewan.

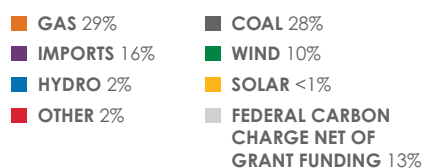
FUEL AND PURCHASED POWER

SaskPower's fuel and purchased power costs include the fuel charges associated with the electricity generated from SaskPower-owned facilities, costs associated with power purchase agreements (PPAs), as well as electricity imported from markets outside Saskatchewan. This electricity is used to serve our company's Saskatchewan customers, with surplus electricity being sold to markets outside the province when favourable conditions exist.

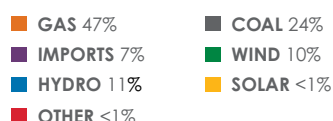
SaskPower's fuel cost management strategy focuses on the economic dispatch of the generating units that bring the lowest incremental cost units online first. Included in the incremental cost is the federal price of carbon on generation that exceeds the allowable emission thresholds.



NET FUEL AND PURCHASED POWER - \$1,105 MILLION



GROSS ELECTRICITY SUPPLIED - 26,174 GWh



(in millions)	2024-25	2023-24	Change
Gas	\$ 316	\$ 366	\$ (50)
Coal	313	296	17
Imports	173	178	(5)
Wind	108	84	24
Hydro	18	16	2
Solar	8	6	2
Other	25	25	-
Total fuel and purchased power	961	971	(10)
Federal carbon charge	280	269	11
Grant funding	(136)	-	(136)
Fuel and purchased power (net)	\$ 1,105	\$ 1,240	\$ (135)

(in GWh)	2024-25	2023-24	Change
Gas	12,426	11,934	492
Coal	6,245	7,895	(1,650)
Imports	1,929	2,027	(98)
Wind	2,531	1,981	550
Hydro	2,769	2,490	279
Solar	94	71	23
Other	180	177	3
Gross electricity supplied	26,174	26,575	(401)

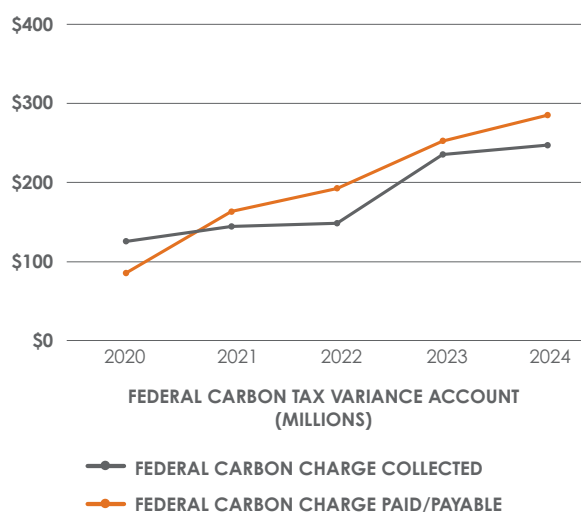
Total fuel and purchased power costs, excluding the federal carbon charge and grant funding, were \$961 million in 2024-25, down \$10 million from 2023-24. The \$10 million decrease is a result of favourable volume and fuel mix variances, partially offset by unfavourable price variance. Total generation and purchased power of 26,174 GWh decreased 401 GWh or 1.5% compared to 2023-24, due to lower customer demand and exports. The reduced electricity supplied resulted in an estimated \$14 million decrease in fuel and purchased power costs. In addition, the change in the fuel mix due to the increased hydro generation availability and the use of lower costing natural gas generation resulted in an estimated \$8 million decrease in fuel and purchased power costs. Average natural gas prices dropped approximately \$0.60 per gigajoule compared to prior year. These decreases were partially offset by an estimated \$12 million increase in fuel prices primarily from higher contracted coal, import, waste heat and solar prices.

Federal carbon charges increased \$11 million as a result of the federal carbon tax rate increasing to \$95/tonne of CO₂e, effective January 1, 2025. This increase was offset by the \$136 million of Clean Electricity Transition Grant funding received from the province in 2024-25, which has been applied against fuel and purchased power costs.

FEDERAL CARBON TAX VARIANCE ACCOUNT (FCTVA)

SaskPower accumulates differences between the federal carbon charge revenue collected from customers and the federal carbon tax owing in a Federal Carbon Tax Variance Account (FCTVA). The balance in the FCTVA, which is not included in SaskPower's financial statements, is either recovered from or refunded to customers as part of federal carbon charge rates. The other recoveries (expense) relate to interest earned on the monies in the account and federal carbon charges associated with exported generation.

(in millions)	Rate rider increase	\$/tonne CO ₂ e	Federal carbon charge receipts/receivables	Federal carbon charge payments/payables	Other recoveries (expense)	Over (under) collected
Total federal (2019 - 2022 calendar years)			\$ 466	\$ (496)	\$ 18	\$ (12)
Total 2023 calendar year	3.0%	\$ 65	235	(252)	29	12
Total 2024 calendar year	0.5%	80	248	(285)	20	(17)
Total 2025 calendar year (three months)	2.9%	95	87	(81)	3	9
Total provincial			\$ 570	\$ (618)	\$ 52	\$ 4
Total cumulative balance	11.7%		\$ 1,036	\$ (1,114)	\$ 70	\$ (8)



Effective January 1, 2019, the Government of Canada introduced a federal carbon tax that was applied to SaskPower's fossil fuel emissions, including those from coal- and natural gas-fired generating stations. SaskPower began recovering the expense associated with the federal carbon tax from its customers through a rate rider effective April 1, 2019. The rate rider is typically adjusted on January 1 of each year to reflect any changes in the estimated carbon tax for the upcoming calendar year. The revenue associated with the federal carbon charge rate rider is being set aside and is used to fund the federal carbon tax payments. As at March 31, 2025, the FCTVA had a balance of \$8 million under collected from customers.

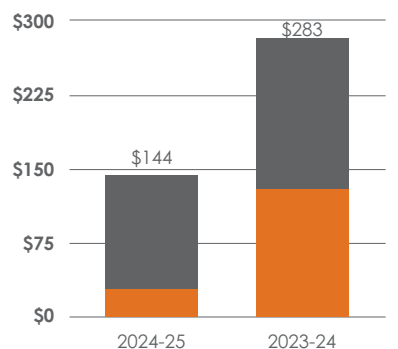
In July 2023, the Government of Canada approved the Saskatchewan Output-Based Performance Standards (OBPS) Program as a replacement for the Federal OBPS Program retroactive to January 1, 2023. Therefore, since 2023 the federal carbon charges were paid to the Government of Saskatchewan, as well as certain independent power producers.

The carbon tax monies paid to the federal government are being returned to SaskPower by way of grant funding agreements, through the Government of Canada's Future Electricity Fund (FEF), in support of current and future clean electricity projects. In 2024-25, \$75 million in FEF grant funding was recognized and applied against both capital and operating costs. During the year, the Government of Saskatchewan, through the Ministry of Environment also provided a \$140 million Clean Electricity Transition Grant (CETG) to SaskPower for use toward eligible initiatives, including clean electricity power purchase agreements; customer clean electricity and demand side management programs; importing renewable power; and costs associated with the development of nuclear small modular reactors. The \$140 million of CETG grant funding received was applied to both fuel and purchased power and operating costs.

SaskPower paused collection of the federal carbon charge rate rider effective April 1, 2025, as mandated by the Government of Saskatchewan.

REVENUE FROM OTHER SOURCES

Revenue from other sources includes exports, which represent the sale of SaskPower's available generation to neighbouring markets and other revenue, which includes various non-electricity products and services.



REVENUE FROM OTHER SOURCES (MILLIONS)

■ EXPORTS
■ OTHER REVENUE

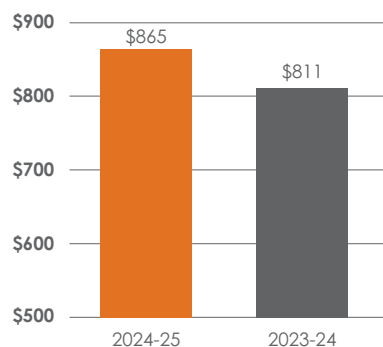
(in millions)	2024-25	2023-24	Change
Exports	\$ 28	\$ 129	\$ (101)
Other revenue	116	154	(38)
Revenue from other sources	\$ 144	\$ 283	\$ (139)

Exports were \$28 million in 2024-25, down \$101 million from 2023-24 due to decreased volumes sold at lower average sale prices. Export sales volumes – primarily to Alberta and the Southwest Power Pool – were 438 GWh, down 325 GWh compared to 2023-24. The average export sales price was \$64 per megawatt hour (MWh), down \$105 per MWh compared to 2023-24.

Other revenue was \$116 million in 2024-25, down \$38 million from 2023-24. The decrease was mainly attributable to lower customer contributions and CO₂ sales.

OPERATING, MAINTENANCE AND ADMINISTRATION (OM&A)

OM&A expense includes salaries and benefits; external services; materials and supplies; and other operating costs.



NET OM&A (MILLIONS)

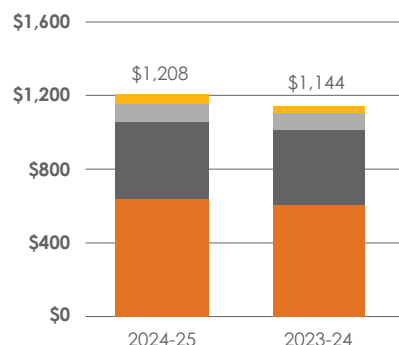
(in millions)	2024-25	2023-24	Change
Total OM&A	\$ 901	\$ 833	\$ 68
Grant funding	(36)	(22)	(14)
OM&A (net)	\$ 865	\$ 811	\$ 54

OM&A expense, excluding grant funding, was \$901 million in 2024-25, up \$68 million from 2023-24. This increase was attributable to increased maintenance at our generation facilities due to the timing of overhaul activities; higher planned maintenance costs on our transmission infrastructure; and increased spending on nuclear development and energy efficiency customer programs.

In 2024-25, the Corporation recognized \$36 million in grant funding from the federal and provincial government which has been applied against operating costs related to the development of nuclear small modular reactors; customer clean electricity and demand-side management programs; and power line technician preparation programs.

CAPITAL-RELATED EXPENSES

Capital-related expenses include depreciation and amortization, finance charges, taxes, and other expenses.



CAPITAL-RELATED EXPENSES (MILLIONS)

- OTHER EXPENSES
- TAXES
- FINANCE CHARGES
- DEPRECIATION AND AMORTIZATION

(in millions)	2024-25	2023-24	Change
Depreciation and amortization	\$ 638	\$ 605	\$ 33
Finance charges	418	409	9
Taxes	100	92	8
Other expenses	52	38	14
Capital-related expenses	\$ 1,208	\$ 1,144	\$ 64

Depreciation and amortization expense was \$638 million in 2024-25, up \$33 million from 2023-24. The increase is primarily due to new capital additions.

Finance charges were \$418 million in 2024-25, up \$9 million from 2023-24. The increase in finance charges was mainly attributable to higher interest on long-term borrowings, partially offset by the combination of higher debt retirement fund earnings, higher interest capitalized and lower interest on short-term borrowings.

Taxes were \$100 million in 2024-25, up \$8 million from the prior year. This increase was largely the result of higher corporate capital tax due to an increase in the paid-up capital base.

Other expenses were \$52 million in 2024-25, compared to \$38 million in 2023-24. The \$14 million increase was mainly attributable to higher adjustments related to inventory and decommissioning provisions.

2024-25 QUARTERLY RESULTS

(in millions)	Q1	Q2	Q3	Q4	Total
Revenue					
Saskatchewan electricity sales	\$ 733	\$ 749	\$ 785	\$ 843	\$ 3,110
Exports	8	8	7	5	28
Other revenue	25	34	31	26	116
Total revenue	766	791	823	874	3,254
Expense					
Fuel and purchased power	263	259	255	328	1,105
Operating, maintenance and administration	223	199	217	226	865
Depreciation and amortization	154	155	159	170	638
Finance charges	96	102	105	115	418
Taxes	24	25	26	25	100
Other expenses	14	8	13	17	52
Total expense	774	748	775	881	3,178
Net income (loss)	\$ (8)	\$ 43	\$ 48	\$ (7)	\$ 76

Fourth quarter year-over-year variance explanation

(in millions)	Three months ended March 31			
	2024-25	2023-24	Change	
Revenue	\$ 874	\$ 856	\$ 18	Increased Saskatchewan electricity sales due to higher carbon charge collected as a result of the 2.9% rate rider increase effective January 1, 2025, partially offset by lower export sales volumes at lower average sale prices.
Expense	881	831	50	Increased OM&A expense attributable to higher maintenance costs at our generation facilities due to the timing of overhaul activities and higher planned maintenance costs on our transmission infrastructure. In addition, capital-related expenses increased due to higher depreciation expense as a result of new capital additions as well as higher interest on long-term borrowings; and higher adjustments related to inventory and decommissioning provisions. These increases were partially offset by lower fuel and purchased power costs primarily as a result of Clean Electricity Transition Grant funding received from the province.
Net (loss) income	\$ (7)	\$ 25	\$ (32)	

FINANCIAL CONDITION

The following table outlines changes in the consolidated statement of financial position from April 1, 2024, to March 31, 2025:

(in millions)	Change (\$)	Change (%)	
Cash and cash equivalents	\$ (324)	(87%)	Refer to the Consolidated Statement of Cash Flows.
Accounts receivable and unbilled revenue	22	5%	Higher grant funding receivables.
Inventory	56	15%	Increase in maintenance supplies, natural gas, and coal inventory.
Prepaid expenses	6	16%	Increase in prepaid licenses.
Property, plant and equipment	1,121	10%	Additions and increased decommissioning asset costs, offset by depreciation expense, asset disposals and retirements.
Right-of-use assets	137	33%	Extension of Meridian Cogeneration Station lease, partially offset by depreciation expense.
Intangible assets	(13)	(16%)	Amortization expense partially offset by capitalization of new software costs.
Debt retirement funds	132	17%	Instalments, earnings, and market value gains.
Other assets	8	30%	Increase in long-term maintenance service costs.
Accounts payable and accrued liabilities	(154)	(18%)	Timing of accruals and payment of federal carbon charges.
Accrued interest	8	10%	Additional long-term debt borrowings.
Deferred revenue	16	94%	Increased customer contributions.
Dividend payable	(5)	(100%)	Payment of Q4 2023-24 dividend.
Risk management liabilities (net of risk management assets)	(10)	(59%)	Settlement of natural gas hedges and increased forward natural gas prices, offset by new hedge contracts.
Short-term advances	(101)	(11%)	Repayment of short-term advances.
Long-term debt (including current portion)	821	11%	Additional issuance of long-term debt, partially offset by repayments.
Lease liabilities (including current portion)	134	16%	Extension of Meridian Cogeneration Station lease agreement, partially offset by principal repayments.
Provisions	328	100%	Increased decommissioning provisions for coal and natural gas facilities.
Equity	108	4%	2024-25 comprehensive income.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk is the risk that the Corporation is unable to meet its financial commitments as they become due or can do so only at excessive cost. SaskPower manages its liquidity risk by ensuring access to funding from the province and maintaining sufficient liquid financial resources which allows for the funding of its commitments in a cost-effective manner.

SOURCES OF FINANCING

SaskPower raises most of its capital through internal operating activities and through borrowings obtained from the Government of Saskatchewan. This type of borrowing allows our company to take advantage of the province's strong credit rating. *The Power Corporation Act* provides SaskPower with the authority to have outstanding borrowings of up to \$10 billion, which includes \$2 billion that may be borrowed by way of temporary loans. Temporary loans include short-term borrowings through the Government of Saskatchewan as well as borrowings made under the \$50 million credit facility provided by a financial institution.

The other major source of financing used by our company is the outstanding \$593 million in equity advances that were provided by Crown Investments Corporation (CIC).

Sources of financing	Authorized amount ¹	Outstanding as at March 31, 2025
Credit facility	\$ 50.0 million	\$ -
Temporary loans (including credit facility)	2.0 billion	0.8 billion
Total borrowings ¹ (including temporary loans)	10.0 billion	9.3 billion

1. Subsequent to March 31, 2025, *The Power Corporation Act* was amended to increase the total authorized borrowings to \$14 billion, which includes \$2 billion that may be borrowed by way of temporary loans.

CREDIT RATINGS - PROVINCE OF SASKATCHEWAN

	2024-25			2023-24		
	Short-term obligations	Long-term obligations	Trend	Short-term obligations	Long-term obligations	Trend
DBRS Morningstar	R-1 (middle) ²	AA (low) ³	Stable	R-1 (middle) ²	AA (low) ³	Stable

2. As per DBRS Morningstar Rating Policies, **R-1 (middle)** denotes superior credit quality. The capacity for payment of short-term financial obligations as they fall due is very high. Differs from R-1 (high) by a relatively modest degree. Unlikely to be significantly vulnerable to future events.

3. As per DBRS Morningstar Rating Policies, **AA** denotes superior credit quality. The capacity for payment of financial obligations is considered high. Credit quality differs from AAA only to a small degree. Unlikely to be significantly vulnerable to future events.

CASH FLOW HIGHLIGHTS

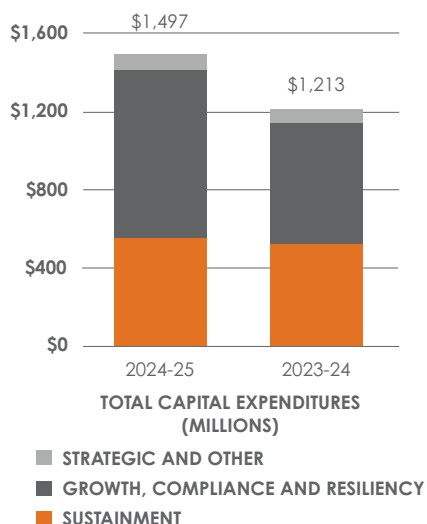
SaskPower's cash flows from operating, investing and financing activities are summarized in the following table:

(in millions)	2024-25	2023-24	Change
Cash and cash equivalents, beginning of year	\$ 374	\$ 192	\$ 182
Cash provided by operating activities	481	751	(270)
Cash used in investing activities	(1,391)	(1,133)	(258)
Cash provided by financing activities	586	564	22
Cash and cash equivalents, end of year	\$ 50	\$ 374	\$ (324)

SaskPower's cash position at March 31, 2025, was \$50 million, down \$324 million from the prior year. SaskPower typically manages its cash position in the \$15 to \$125 million range with the actual cash balance fluctuating throughout the year based on the timing of cash inflows and outflows. The decrease in the cash position is largely due to lower operating cash flows, combined with additional capital expenditures, slightly offset by new long-term borrowings.

CAPITAL EXPENDITURES

(in millions)	2024-25	2023-24	Change
Generation	\$ 182	\$ 155	\$ 27
Transmission	90	92	(2)
Distribution	177	163	14
Other	106	110	(4)
Sustainment	555	520	35
Generation	590	389	201
Transmission	51	39	12
Distribution	22	16	6
Customer connects	192	177	15
Growth, compliance and resiliency	855	621	234
Strategic and other	87	72	15
Total capital expenditures	1,497	1,213	284
Grant funding	(74)	(49)	(25)
Capital expenditures (net)	\$ 1,423	\$ 1,164	\$ 259



In order to ensure a reliable, sustainable and cost-effective supply of electricity for its customers, SaskPower spent \$1.5 billion on various capital projects during 2024-25, compared to \$1.2 billion in 2023-24.

The company invested \$555 million on sustainment activities, including:

- \$182 million on generation assets and \$267 million on transmission and distribution assets; and
- \$106 million for other sustainment expenditures, including \$30 million on building renovations; \$42 million on technology and security assets; and \$27 million on vehicles and equipment.

SaskPower also spent \$855 million on growth, compliance and resiliency investments, including:

- \$590 million on generation assets, including \$420 million on the new Aspen Power Station; \$130 million on new units at Ermine and Yellowhead Power Stations; and \$36 million on the new Great Plains Power Station;
- \$73 million on increasing grid capacity; and
- \$192 million to connect customers to the SaskPower electricity system.

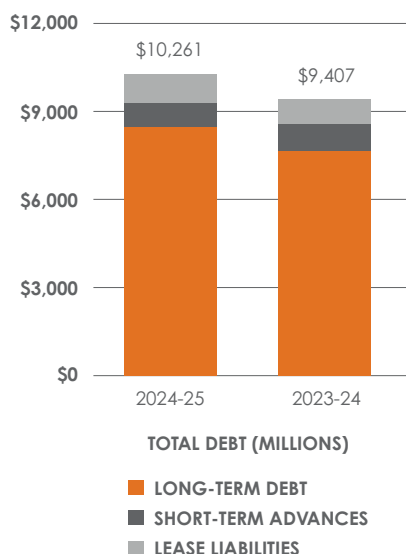
In 2024-25, SaskPower recognized \$74 million in grant funding from the federal government which has been applied against capital project costs.

CAPITAL MANAGEMENT

(in millions)	March 31, 2025	March 31, 2024	Change
Long-term debt	\$ 8,468	\$ 7,647	\$ 821
Short-term advances	809	910	(101)
Lease liabilities	984	850	134
Total debt	\$ 10,261	\$ 9,407	\$ 854
Debt retirement funds	931	799	132
Cash and cash equivalents	50	374	(324)
Total net debt¹	\$ 9,280	\$ 8,234	\$ 1,046
Retained earnings	2,313	2,237	76
Equity advances	593	593	-
Total capital	\$ 12,186	\$ 11,064	\$ 1,122
Per cent debt ratio²	76.2%	74.4%	1.8%

1. Total net debt is a non-GAAP financial measure calculated by deducting debt retirement funds and cash and cash equivalents from total debt.

2. Per cent debt ratio = (total net debt)/(total capital).



Total debt position

SaskPower's total debt position (including lease liabilities) was \$10.3 billion at March 31, 2025, up \$854 million from the prior year. The increase in total debt was the result of the following:

- SaskPower borrowed \$1,021 million of long-term debt as follows:

(in millions)

Date of issue	Date of maturity	Effective interest rate (%)	Coupon rate (%)	Par value	Premium (discount)	Outstanding amount
Apr 17, 2024	Jun 2, 2033	4.50	3.90	\$ 285	\$ (13)	\$ 272
Jun 6, 2024	Dec 2, 2054	4.32	4.20	250	(5)	245
Aug 12, 2024	Dec 2, 2054	4.23	4.20	250	(1)	249
Dec 2, 2024	Dec 2, 2054	4.10	4.20	250	5	255
				\$ 1,035	\$ (14)	\$ 1,021

- On June 3, 2024, the Corporation repaid \$200 million long-term debt. The debt had a coupon rate of 3.20% and an effective interest rate of 1.79%.
- On September 1, 2024, SaskPower signed an amended power purchase agreement related to the Meridian Cogeneration Station, extending the term to December 31, 2049. As such, this lease modification resulted in a \$187 million increase in lease liabilities. In addition, there was a building lease modification of \$1 million. These increases were partially offset by \$54 million in principal repayments of the Corporation's lease liabilities.
- \$101 million in net repayments of short-term advances.

The Corporation's per cent debt ratio increased from 74.4% as at March 31, 2024, to 76.2% as at March 31, 2025.

Debt retirement funds

(in millions)	2024-25	2023-24
Balance, April 1	\$ 799	\$ 717
Debt retirement fund instalments	75	70
Debt retirement fund earnings	32	14
Debt retirement fund unrealized market value gains (losses)	25	(2)
Balance, March 31	\$ 931	\$ 799

Debt retirement funds are monies set aside to retire outstanding long-term debt upon maturity. SaskPower makes regular contributions to the funds, which are held and invested by the Government of Saskatchewan's General Revenue Fund.

During the year ended March 31, 2025, SaskPower made \$75 million in contributions to the debt retirement funds on outstanding debt issues as required by the terms of the advances from the Government of Saskatchewan's General Revenue Fund. In addition, the Corporation earned \$32 million (included with finance charges and classified as non-cash operating activities) on the debt retirement funds for the year. The debt retirement funds are classified as fair value through other comprehensive income. As a result, \$25 million in unrealized market value gains were recognized through other comprehensive income in 2024-25.

DIVIDENDS

SaskPower pays dividends to Crown Investments Corporation (CIC) of Saskatchewan based on the CIC Dividend Policy. CIC has determined that SaskPower will be required to pay a 10% dividend based on 2024-25 net income net of the Clean Electricity Transition Grant funding. SaskPower had a net loss of \$64 million once the funding was removed. As a result, no dividend has been declared for the fiscal year ending March 31, 2025.

CONTRACTUAL OBLIGATIONS

SaskPower has the following significant long-term contractual obligations as at March 31, 2025, which will impact cash flows in the following year and beyond:

(in millions)	1 year	2-5 years	More than 5 years	Total
Power purchase agreements (PPAs) ¹	\$ 651	\$ 3,004	\$ 12,510	\$ 16,165
Long-term debt (including principal and interest)	533	1,758	12,401	14,692
Debt retirement fund instalments	85	328	1,207	1,620
Coal purchase contracts	209	827	-	1,036
Natural gas purchase contracts	131	163	-	294
Natural gas transportation and storage contracts	77	285	388	750

1. The long-term contractual obligations related to PPAs include lease liabilities, operating agreements and long-term import agreements.

CAPITAL INVESTMENTS

SUSTAINMENT INVESTMENTS

Capital sustainment investments include generation, transmission and distribution projects that involve renewing, refurbishing, or replacing existing infrastructure, either through an annual program or one-time project.



RURAL REBUILD AND IMPROVEMENT ANNUAL PROGRAM

TOTAL COST: \$46 MILLION (2025-26) **IN-SERVICE:** ONGOING PROGRAM

The Rural Rebuild and Improvement Program is focused on the strategic replacement of Saskatchewan's aging rural electrical distribution system. It replaces lines with poor reliability performance and facilitates removal of power lines from farm fields while taking into account safety considerations and the optimization of line loss savings.



RURAL UNDERGROUND (RUD) MITIGATION ANNUAL PROGRAM

TOTAL COST: \$29 MILLION (2025-26) **IN-SERVICE:** ONGOING PROGRAM

The objective of the RUD mitigation program is to replace aging rural underground distribution primary cable that is at or approaching end of life.

GROWTH, COMPLIANCE AND RESILIENCY INVESTMENTS

Growth, compliance and resiliency investments include new generation, transmission or distribution additions to accommodate growth in demand, customer connections and other projects.



SOUTHWEST POWER POOL INTERCONNECTION

TOTAL COST: \$533 MILLION **IN-SERVICE:** 2027-28

The purpose of this project is to facilitate an additional 500 MW of long-term transmission service between the Southwest Power Pool and SaskPower. This project includes building two new 6 km 230 kV single circuit International Power Lines (IPL), the Tableland switching station, two new 20 km transmission lines from the Tableland switching station to existing SaskPower lines in the area, and system reinforcements to accommodate the IPL interconnection in the Rowatt area.



GREAT PLAINS POWER STATION

TOTAL COST: \$825 MILLION **IN-SERVICE:** DECEMBER 2024

Construction is completed on the 370-MW natural gas-fired combined cycle generating station. The Great Plains Power Station is located in Moose Jaw and came into service in December 2024. This new power station will provide generation to serve increased load and support the integration of renewable generation on the power grid.



ERMINES AND YELLOWHEAD POWER STATIONS EXPANSION

TOTAL COST: \$379 MILLION

IN-SERVICE: 2025-26

This expansion project will add a 46-MW natural gas-fired simple cycle generation unit to each of the facilities at the Ermine and Yellowhead Power Stations. The new gas turbines are expected to be in service by the end of 2025.



ASPEN POWER STATION

TOTAL COST: \$1.7 BILLION

IN-SERVICE: 2027-28

Construction is underway on a new 370-MW natural gas-fired combined cycle generating station. The Aspen Power Station is located near Lanigan and is expected to be in service in 2027. This new power station is part of a staged approach to serve increased load as well as support the addition of new intermittent wind and solar generation projects.

A detailed list of the Corporation's future new generation projects greater than 5 MW is listed below:

FUTURE NEW GENERATION PROJECTS				
Project name	Net capacity (MW)	Fuel source	Ownership	Estimated commissioning year
Aspen Power Station	370	Natural gas	SaskPower	2027-28
Rose Valley Wind Energy Project	200	Wind	IPP	2027-28
Seven Stars Wind Energy Project	200	Wind	IPP	2027-28
Southern Springs Solar Energy Project	100	Solar	IPP	2027-28
Iyuhána Solar Energy Project	100	Solar	IPP	2027-28
Coleville Gas Generating Project	27	Natural gas	IPP	2027-28
North Portal Gas Generating Project	27	Natural gas	IPP	2027-28
SEEP Gas Generating Project	25	Natural gas	IPP	2027-28
Steelman Gas Generating Project	23	Natural gas	IPP	2027-28
Viewfield Gas Generating Project	23	Natural gas	IPP	2027-28
Flying Dust Gas Generating Project	20	Natural Gas	IPP	2028-29
DEEP Geothermal Energy Project	5	Geothermal	IPP	2028-29

STRATEGIC AND OTHER INVESTMENTS

Strategic and other investments include upgrades and improvements to technology and security, supply chain, and strategic and non-discretionary projects.



REGINA OPERATIONS AND MAINTENANCE COMPLEX

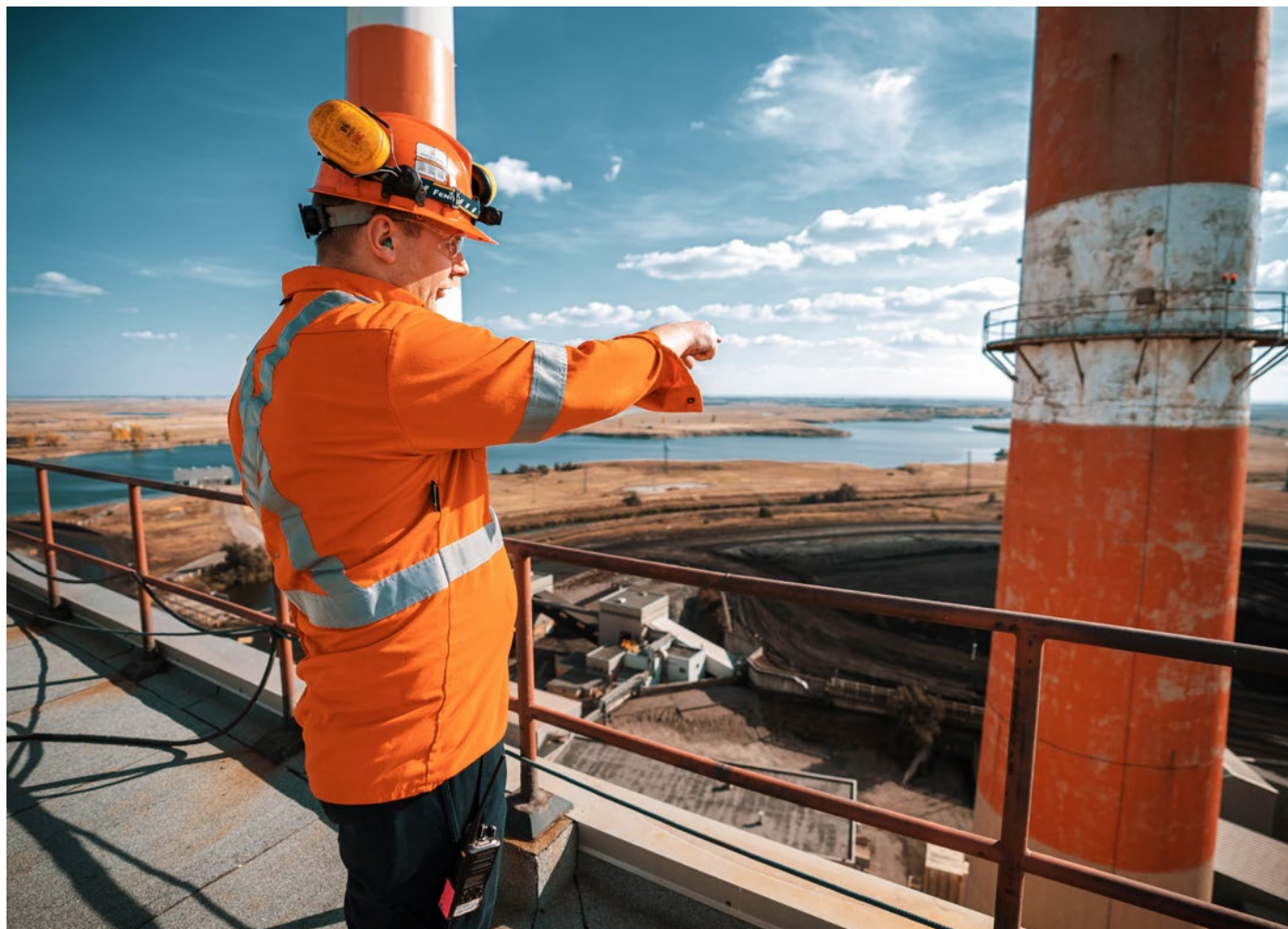
TOTAL COST: \$280 MILLION

IN-SERVICE: 2026-27

The Regina Operations and Maintenance Complex will result in a new 97-acre facility consolidating SaskPower operations that are currently located at the Regina Service Centre, Federal Pioneer building, Regina Maintenance Centre, Lumsden field office, Broder Street furniture warehouse, and White City Pole Yard. The complex will replace current SaskPower building assets which are at the end of their effective lifecycle and facilitate multiple operational efficiencies.

OUTLOOK

The 2025-26 earnings expectations are subject to a number of variables, including natural gas prices; coal and hydro availability; weather; economic conditions; number of customers; new and changing regulations; supply chain; and market conditions in other jurisdictions.



2025-26 NET INCOME

SaskPower's net income is expected to be \$126 million in 2025-26, up \$50 million from 2024-25, resulting in a return on equity of 4.3%. This is primarily due to a projected increase in electricity sales demand, higher customer contributions and increased export opportunities.

In addition, operating expenses are expected to increase due to inflation, and an increase in overhauls, technology, and vegetation management spending; higher depreciation and amortization expense as a result of additional capital expenditures; and increased finance charges due to higher expected interest on borrowings and lease liabilities.

2025-26 CAPITAL EXPENDITURES

SaskPower is forecasting to spend \$1.8 billion in total capital expenditures in 2025-26. This record capital investment will improve reliability, replace aging infrastructure and support the energy transition by reducing emissions and modernizing the grid. The capital spend includes \$686 million on sustainment activities; over \$1.0 billion in growth, compliance, and resiliency activities, of which \$594 million relates to the construction of the new Aspen Power Station; \$277 million to connect customers to the SaskPower electricity system; and \$141 million to increase grid capacity.

PLANNING FOR NUCLEAR POWER

In response to the need for new power generation options that deliver reliable service in support of Saskatchewan's economic growth, SaskPower is making significant investments into assessing the viability of nuclear small modular reactors (SMRs) as a possible cornerstone of the company's long-term energy plan.

The company's SMR evaluation efforts gained momentum over the past 12 months, with a specific focus on advancing technical assessments and building SaskPower's capacity to support SMR licensing applications. At the same time, we continued to forge strong relationships with Indigenous Rights Holders, potential host communities and the broader Canadian nuclear industry.

Although a final investment decision to build an SMR won't be made until 2029, robust planning work is required now if SMRs are going to be a part of our province's generation mix by the mid-2030s.

SITE SELECTION AND STAKEHOLDER ENGAGEMENT

In May 2024, SaskPower announced that the potential site for Saskatchewan's first SMR had been narrowed down to two locations near Estevan. Further detailed technical and environmental evaluations of these two short-listed sites are underway.

Engagement with the public, communities, customers, stakeholders and Indigenous Rights Holders remained a core part of SaskPower's SMR planning work over the past 12 months. Much of our focus was related to communities, municipalities and Indigenous Rights Holders in the two shortlisted site locations, to better understand their interests and concerns. Engagement highlights from 2024 included in-person visits with the Pheasant Rump Nakota First Nation, White Bear First Nation, Carry the Kettle Nakoda Nation, and Ocean Man First Nation. Walks with Indigenous Rights Holders at the two potential SMR sites also allowed for a first-hand view.

Meanwhile, in June 2024, SaskPower was the proud host of the 43rd Annual Nuclear Society Conference in Saskatoon. The conference attracted more than 300 nuclear industry experts, professionals and students to Saskatchewan. In the fall of 2024, members of the International Atomic Energy Agency visited the two potential SMR locations near Estevan, as part of their review of SaskPower's site selection process.

FINANCIAL IMPACTS

Throughout the planning process, the net costs associated with the development of SMRs was \$18 million as of March 31, 2025.

(in millions)	2021-22	2022-23	2023-24	2024-25	Total
Salaries and benefits	\$ 1	\$ 1	\$ 4	\$ 7	\$ 13
Contract services	4	9	12	20	45
Other	-	1	-	1	2
Total OM&A	5	11	16	28	60
Grant funding	-	-	(16)	(26)	(42)
OM&A (net)	\$ 5	\$ 11	\$ -	\$ 2	\$ 18

DEVELOPMENT OF NUCLEAR EXPERTISE

During 2024-25, SaskPower continued to expand its nuclear expertise, supported by the appointment by the Lieutenant Governor in Council of Rumina Velshi, former President and CEO of the Canadian Nuclear Safety Commission, as a member of the SaskPower's Board of Directors. In 2024, SaskPower also signed a Memorandum of Understanding (MOU) with Cameco and Westinghouse to explore opportunities for collaboration in several areas including reactor technology deployment, nuclear supply chain development, nuclear fuel fabrication, nuclear research and development and nuclear workforce training. In addition, SaskPower and the Saskatchewan Research Council joined Conexus Nuclear (formerly the CANDU Owners Group). Conexus Nuclear is one of Canada's leading nuclear industry technical research and engineering organizations with a focus on training, safety, licencing, regulatory and environmental affairs, nuclear fuel development and supply, nuclear plant operations and sustainable management of used nuclear fuel and other nuclear waste. SaskPower's membership in Conexus Nuclear gives us access to world class nuclear research, technical workshops and peer groups focused on environmental and regulatory affairs, nuclear safety, used fuel management and emergency planning.

In 2024, SaskPower President and CEO Rupen Pandya was elected to the Board of Directors of the Canadian Nuclear Association, the global voice of Canada's nuclear industry.

SaskPower's growing engagement with Canada's nuclear industry builds on MOUs and Collaboration Agreements signed over the past decade with Canada's nuclear utilities — Ontario Power Generation (OPG), New Brunswick Power and Bruce Power. SaskPower has also played a leadership role in the development of the Canadian SMR Roadmap (2018), the Government of Canada's SMR Action Plan (2020), the development of a major SMR Feasibility Report in partnership with OPG and New Brunswick Power (2021) and the release by the Governments of Saskatchewan, New Brunswick and Ontario of a Strategic Plan to Advance Small Modular Reactors (2022).

NEXT STEPS

SaskPower created a new corporate subsidiary — SaskNuclear — and put together a dedicated team focused on building the internal capacity required to successfully file three complex licensing applications required by the Canadian Nuclear Safety Commission: for site preparation, for SMR construction, and for SMR operation.

SaskPower is now nearing completion of its first phase of SMR development which will culminate in 2025-26 with the selection of a site for Saskatchewan's first nuclear power plant and the submission of an Initial Project Description to the Impact Assessment Agency of Canada which will formally launch the nuclear licensing process.

Ongoing consultation with the public, stakeholders and Indigenous Rights Holders will continue throughout the process of nuclear power plant licencing, construction and operation. SaskPower will also continue to work with the Saskatchewan Industrial and Mining Suppliers Association (SIMSA) and the Saskatchewan business community to support the development of a nuclear qualified supply chain required to build and operate nuclear power plants.

SaskPower will continue to collaborate with Saskatchewan post-secondary institutions to build the research and training capacity required to establish and maintain a nuclear qualified workforce.



RELATED PARTY TRANSACTIONS

SaskPower has a number of routine transactions with various Saskatchewan Crown corporations, ministries, agencies, boards, and commissions related to our company by virtue of common control by the Government of Saskatchewan. These transactions with related parties are settled at prevailing market prices under normal trade terms. Related party transactions are disclosed in Note 31 to the consolidated financial statements.

ANALYSIS OF CRITICAL ACCOUNTING POLICIES, ESTIMATES AND JUDGMENTS

SaskPower's material accounting policies are described in Note 3 to the consolidated financial statements. Some of these policies involve accounting estimates that require management to make particularly subjective or complex judgments about matters that are inherently uncertain. Different conditions or assumptions regarding the estimates could result in materially different results being reported. Management has discussed the development and selection of these critical accounting policies with the Board of Directors and the external auditors.

The following section discusses the critical accounting estimates and areas of judgment in applying accounting policies that have the most significant effect on the amounts reported in the consolidated financial statements.

Consolidated statement of financial position

(in millions)	March 31, 2025	March 31, 2024
Unbilled revenue receivable	\$ 84	\$ 90
Expected credit loss allowance	18	19
Allowance for obsolescence	21	19
Debt retirement funds	931	799
Net risk management liabilities (assets)	7	17
Decommissioning provisions	565	261
Environmental remediation liabilities	90	66
Defined benefit pension plan deficit	17	19

Consolidated statement of income

(in millions)	2024-25	2023-24
Depreciation and amortization expense	\$ 638	\$ 605

UNBILLED REVENUE RECEIVABLE

Electricity revenues are billed on a systematic basis. At the end of each month, SaskPower makes an estimate of the electricity delivered to its customers since their last billing date. The estimated unbilled revenue is based on several factors, including estimated consumption for each customer, applicable customer rates and the number of days between the last billing date and the end of the period. As at March 31, 2025, total Saskatchewan electricity sales of over \$3.1 billion included \$84 million of estimated unbilled revenue.

EXPECTED CREDIT LOSS ALLOWANCE

An expected credit loss allowance is calculated for both energy and non-energy sales. Loss rates are based on historical credit losses and are adjusted to reflect differences between current and historical economic conditions and the Corporation's view of economic conditions over the expected lives of the receivables. The expected credit loss allowance is reviewed quarterly based on an estimate of outstanding amounts that are considered uncollectible. Historically, SaskPower has not written off a significant portion of its accounts receivable balances.

ALLOWANCE FOR OBSOLESCENCE

An allowance for obsolescence is calculated for generation, transmission, and distribution inventory. In establishing the appropriate provision for inventory obsolescence, management estimates the likelihood that inventory on hand will become obsolete due to changes in technology and regulations.

DEBT RETIREMENT FUNDS

Debt retirement funds are monies set aside to retire outstanding debt upon maturity. The debt retirement funds are recorded at fair value on the balance sheet. The fair value adjustment is based upon closing period-end prices received from the Government of Saskatchewan Ministry of Finance.

NET RISK MANAGEMENT LIABILITIES (ASSETS)

Net risk management liabilities (assets) reflect the fair value of the derivative financial instruments on the balance sheet. Derivative financial instruments include natural gas forward contracts designated as cash flow hedges. The fair values are determined using independent pricing information from external market providers.

PROVISIONS

Decommissioning

A decommissioning provision is a legal or constructive obligation associated with the retirement of a long-lived asset. The calculations of fair value are based on detailed studies that take into account various assumptions regarding anticipated future cash flows, including the method and timing of decommissioning and estimates of future inflation. In 2024-25, SaskPower engaged a third-party consultant to review its decommissioning and reclamation plans for its coal and natural gas facilities. As a result of the review, it was determined that the estimated amount of cash flows required to settle these liabilities should be increased. This change in estimate was recognized as an increase in the carrying amount of the decommissioning provision and the related generation asset.

Environmental remediation

A provision for environmental remediation is accrued when the occurrence of an environmental expenditure, related to present or past activities of SaskPower, is considered probable and the costs of remedial activities can be reasonably estimated. The fair value of the estimated costs for investigations and remediation at identified sites is recorded as a provision in profit or loss as other expenses. These provisions are based on management's best estimate considering current environmental laws and regulations and are recorded at fair value. SaskPower reviews its estimates of future environmental expenditures on an ongoing basis.

DEFINED BENEFIT PENSION PLAN DEFICIT

SaskPower provides post-retirement benefits to employees, including those from a defined benefit pension plan (the Plan). An independent actuary calculates the funded status of the Plan every three years based on assumptions regarding discount rates, inflation rates, future pension indexing and life expectancy. The funded status is extrapolated on a quarterly basis for the current discount rate. The entire deficit for the defined benefit pension plan is recognized on the statement of financial position.

DEPRECIATION AND AMORTIZATION

Property, plant and equipment represent 83% of total assets recognized on SaskPower's consolidated statement of financial position as at March 31, 2025. Included in property, plant and equipment are the generation, transmission, distribution and other assets of SaskPower. Due to the size of SaskPower's property, plant and equipment, changes in estimated depreciation rates can have a significant impact on income.

Depreciation is recognized on a straight-line basis over the estimated useful life of each component of property, plant and equipment. The estimated useful lives of the components are based on formal depreciation studies that are performed typically every five years, with annual reviews for reasonableness. A one-year decrease in the average estimated service life of each of the major asset classes of property, plant and equipment would result in a \$34 million increase to depreciation expense annually.

ESTIMATED USEFUL LIVES

Judgment has been used to determine the estimated useful lives and related accelerated depreciation for coal-fired generation facility assets based on federal regulations.

IDENTIFICATION OF ARRANGEMENTS WHICH CONTAIN A LEASE

In assessing the carrying amounts of right-of-use assets and lease liabilities and underlying estimates of future cash flows, management must use judgment in identifying which arrangements contain a lease as well as the lease term for contracts, including renewal options for which SaskPower is the lessee.

REVENUE RECOGNITION OF CUSTOMER CONTRIBUTIONS

Customer contributions are funds received from certain customers toward the costs of service extensions. In determining when to recognize revenue related to customer contributions, management is required to make judgments in regard to when the related property, plant and equipment is available for use and performance obligations are complete.

RECENT AND FUTURE ACCOUNTING POLICY CHANGES

The following new standards and amendments to existing IFRS Accounting Standards as issued by the International Accounting Standards Board (IFRS) have been issued, however, are not yet effective for the year ended March 31, 2025, and have not been applied in preparing the consolidated financial statements (refer to Note 2e). The Corporation is currently reviewing the following new and amended standards to determine the potential impact on its consolidated financial statements:

- Amendments to IFRS 9, *Financial Instruments*, related to the classification and measurement of Financial Instruments to clarify the timing of recognition and derecognition for a financial asset or financial liability, including clarifying that a financial liability is derecognized on the settlement date. In addition to these clarifications, the amendments introduce an accounting policy choice to derecognize financial liabilities settled using an electronic payment system before the settlement date if specific conditions are met.
- Amendments to IFRS 9 *Financial Instruments*, apply to contracts referencing nature-dependent electricity to help companies better report the financial effects of these contracts, which are often structured as power purchase agreements (PPAs). Amendments include allowing the sale of un-used nature-dependent electricity to apply for the own-use scope exemption; and allowing an entity to apply hedge accounting to nature-dependent electricity transactions if specified criteria are met.
- IFRS 18, *Presentation and Disclosure in the Financial Statements*, which will replace IAS 1, *Presentation of Financial Statements*. The new standard will require classification of income and expense into specified categories, defined subtotals and management-defined performance measures. The new standard also provides guidance on aggregation and disaggregation of disclosures.

RISK MANAGEMENT

SaskPower operates in a complex and dynamic business environment. Significant pressures, uncertainties, and changes are occurring in the industry. As part of the strategic planning process, major challenges to our business have been identified which introduce a variety of risks and uncertainties that could impact the achievement of our business objectives. In addition to strategic risk, functional risks are identified, managed and to the extent possible mitigated through the Enterprise Risk Management (ERM) Program. These functional risks include: financial performance, operational performance, safety, compliance, and reputation. SaskPower's risk management responses are implemented in various ways, including through governance practices, policies, procedures, processes, and technologies. The ERM Program promotes a consistent and standard approach to risk identification, assessment, and management throughout the organization. Through the program, SaskPower's Board of Directors and Executive Members continue to identify and respond to developing and potential new risks. In this uncertain environment, corporate risk management efforts are aligned to allow SaskPower to continue to deliver reliable and affordable power in Saskatchewan.

ERM GOVERNANCE

Risk management is the responsibility of all employees and is an integral part of our culture. SaskPower's Board of Directors has overall responsibility for stewardship of the Corporation and the President and CEO has ultimate accountability for risk management, with support from Executive Members. Executive Members manage key business risks, including new and emerging risks and opportunities. The Audit & Finance Committee of the Board is responsible for overseeing the ERM framework, risk management policies, authorities, and accountabilities of shared risk management throughout SaskPower.

SaskPower's business divisions are responsible for managing day-to-day risks within their areas of responsibility. Project risks are the responsibility of project managers, with corresponding accountability to project boards and respective Executive Members.

TOP CORPORATE RISKS

Our company is challenged by regulatory requirements; early engagement with Indigenous and non-Indigenous communities on projects and initiatives planned to meet the needs of the electricity system; the need for new electricity supply; financial constraints; economic disruptors; evolving technologies; growing capital requirements; and the speed at which stakeholder and customers' expectations are changing. SaskPower annually identifies top corporate risks that could impact our company's corporate strategies and priorities; influence financial and operating results; and affect achievement of our business objectives.

SaskPower's risk portfolio evolves over time, with significant shifts to focus on key emerging issues and priority initiatives. Our company regularly undertakes routine and non-routine projects as well as strategic initiatives to meet evolving regulatory requirements, customer demands, and load conditions. These projects and initiatives involve significant investment and require strategic risk management to support investment decision making.

1. REGULATION

The Corporation is subject to extensive federal, provincial and municipal regulations. Failure to comply with these regulations could result in fines or other penalties.

SaskPower continues to assess the federal regulatory environment. Meanwhile, the Corporation has worked with the provincial government to streamline project permitting requirements through the Red Tape Reduction initiative. Additionally, the Corporation continues to assess the federal regulatory environment.

2. FINANCIAL SUSTAINABILITY

SaskPower's financial flexibility and capability are challenged by current economic conditions, growing capital requirements, increasing debt, and pressures to maintain competitive rates. SaskPower has a high fixed-cost structure driven by the capital-intensive nature of the electric utility business. SaskPower's business model needs to be agile enough to adapt to industry changes, including emissions requirements, rising costs, capital expenditures and customer self-generation. Key financial drivers include revenues which are impacted by load growth, provincial economic conditions, customer mix, and approved rate increases. The cost of fuel is driven by load growth, fuel mix, and the market price of fuel. Depreciation and finance charges are impacted by capital expenditures and the cost of borrowing.

SaskPower minimizes the impact of current financial constraints by implementing business optimization initiatives; using scenario-based budgeting and forecasting for business planning; prioritizing capital spending; engaging in cost-effective financing; diversifying the fuel mix; developing a rate management strategy; monitoring counterparty credit risk; validating load forecast assumptions; hedging natural gas requirements; maintaining rate competitiveness and identifying the most cost-effective supply options.

3. INFRASTRUCTURE, RELIABILITY, AND ENERGY SUPPLY

Significant capital spending is required to maintain system reliability, reduce risk of equipment failures, renew aging infrastructure, and accommodate growing demand for electricity. SaskPower's electricity supply infrastructure can be affected by age, insufficient capital investment, significant technological change, innovation, and growing customer demand and expectations. A large portion of SaskPower's critical generation, transmission and distribution assets are near or at the end of their expected service life.

Performance, reliability, and maximized uptime of existing generation, transmission, and distribution facilities are fundamental to maintaining a safe, continuous, and adequate supply of electricity. Information technology system requirements are evolving to manage the power system more efficiently and maintain acceptable security standards.

SaskPower manages fuel supply risks through strategies that include long-term natural gas transmission contracts; long-term coal contracts to address price, quality and security of supply; and feasibility study of small modular reactors using nuclear as a source fuel.

4. ENERGY POLICY

The Corporation is challenged as the utility industry is in the midst of a major infrastructure investment cycle within a shifting energy policy environment in North America and the world. The bulk of SaskPower infrastructure is either coming to the end of its useful life and needs to be renewed or replaced. The traditional electricity grid is evolving into a system in which automation, remote control, visibility, and customer participation are expected. Customers will become more integrated in the Corporation's network through customer-owned generation and energy management products by providing input on long-term decision making.

The Corporation has strategies to define the path forward within a changing energy policy environment, including a diverse supply plan. A cross-functional team works with various stakeholders to address disruption resulting from distributed and self-generation technologies. SaskPower continues to explore new opportunities for cogeneration with large industrial customers and nuclear generation options.

5. INDIGENOUS ENGAGEMENT

SaskPower interacts with a variety of Indigenous communities and Rights Holders within the scope of its operations. Indigenous expectations include greater transparency, involvement, and stewardship. Positive engagement through effective communication of SaskPower's needs and strategic direction helps our company achieve its objectives and deal with adversity or significant change when it impacts the organization and Indigenous stakeholders. SaskPower continues to facilitate engagement with Indigenous Rights Holders related to plans for the power system in Saskatchewan.

6. SECURITY

SaskPower business operations rely on information and operational technologies which need to be maintained, supported, protected, and secured while enabling appropriate access and ensuring reliability, confidentiality, integrity, and availability of associated systems and information. Demand for security capabilities will increase as threats continue to evolve.

SaskPower has established physical and cyber security controls to defend our servers, networks, and data from attack, damage, or unauthorized use. Identity and access management controls restrict unauthorized access of data and malicious manipulation of data by external or internal actors. Data loss prevention techniques have been deployed to identify, monitor, and prevent inappropriate sharing of sensitive and confidential information. System vulnerabilities are managed by hardening servers and encrypting mobile assets. SaskPower employees are equipped with various security awareness techniques and training to understand emerging phishing and artificial intelligence risks.

7. SAFETY

SaskPower operations can inherently impact the safety of employees, contractors, customers, and the general public. There are considerable hazards and risks associated with working on high voltage equipment, on equipment operated at a high temperature or pressure, at heights, with chemicals, and around large machines. SaskPower interacts with customers, contractors, and the public to inform them of potential safety issues.

SaskPower mitigation strategies include the integration of leadership competencies to foster and reinforce safe work practices. The Standard Protection Code and Standard Operating Procedures have been embedded in SaskPower's safety culture and operations. Contractors and employees are provided with safety orientations and learning opportunities for compliance with legislation and corporate safety requirements. Safety goals and the Corporate Balanced Scorecard Health & Safety Index are also incorporated into our company's performance management process. Risk-based asset maintenance programs at SaskPower include equipment inspection, replacement, and maintenance. The asset maintenance program is designed to reduce the risk of public injuries or fatalities. Partnerships are continuing with the Government of Saskatchewan Ministry of Agriculture and other public and private organizations to raise awareness of public safety in a way that will reduce farming and construction-related incidents.

8. PROJECT DELIVERY AND SUPPLY CHAIN

SaskPower has identified the need to invest significant amounts of capital in long-term projects to ensure continued reliability — this includes maintaining, upgrading, and expanding infrastructure. The Corporation continues to deliver on significant projects related to customer connects, service delivery improvements, refurbishment of existing infrastructure, and new supply options. All of these projects are competing for human resources as well as financial, operating, and capital resources. As well, new regulations, stakeholder expectations, and financial constraints place increasing demands on the company.

Delay or quality of material may result in not delivering projects on schedule or within budget, therefore increasing costs for the Corporation and potentially impacting reliability. SaskPower mitigation strategies include standardizing project delivery tools and governance methods; implementing vendor prequalification and provision for long-term goods and service contracts; tracking earned value metrics for each project; managing project risks through cross-functional risk committees; as well as comprehensive monitoring and reporting of project dependencies and outage scheduling.

9. PEOPLE AND SKILLS

Over the next decade, continued success will be tied to SaskPower's ability to train, attract, and retain sufficiently qualified staff to meet business needs. SaskPower will focus on succession planning, skillset gap analysis, retention strategies, targeted recruitment for in-demand occupations, and continuous improvement training. The Corporation is continuing to build partnerships with educational institutions and support apprenticeship programs to assist in meeting our workforce needs.

CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

For the year ended March 31, 2025

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REPORT OF MANAGEMENT

The consolidated financial statements of Saskatchewan Power Corporation (SaskPower; the Corporation) are the responsibility of management and have been prepared in accordance with IFRS® Accounting Standards as issued by the International Accounting Standards Board (IFRS). The preparation of financial statements necessarily involves the use of estimates based on management's best judgment, particularly when transactions affecting the current period cannot be finalized with certainty until future periods. In management's opinion, the consolidated financial statements have been properly prepared within the framework of selected accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, information available up to May 28, 2025. The financial information presented in the Management's Discussion & Analysis (MD&A) and elsewhere in this report is consistent with that in the consolidated financial statements.

Management maintains appropriate systems of internal control which provide reasonable assurance that the Corporation's assets are safeguarded and appropriately accounted for, that financial records are relevant, reliable, and accurate, and that transactions are executed in accordance with management's authorization. This system includes corporate-wide policies and procedures, as well as the appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of these controls on an ongoing basis and reports its findings to management and the Audit & Finance Committee of the Board of Directors.

The Board of Directors, through the Audit & Finance Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit & Finance Committee consists entirely of outside Directors. At regular meetings, the Committee reviews audit, internal control and financial reporting matters with management, the internal auditors and the external auditors to satisfy itself that each is properly discharging its responsibilities. The financial statements and the Independent Auditor's Report have been reviewed by the Audit & Finance Committee and have been approved by the Board of Directors. The internal and external auditors have full and open access to the Audit & Finance Committee, with and without the presence of management.

The consolidated financial statements have been examined by Deloitte LLP, Chartered Professional Accountants, as appointed by the Lieutenant Governor in Council and approved by the Crown Investments Corporation of Saskatchewan. The external auditor's responsibility is to express its opinion on whether the consolidated financial statements are fairly presented in accordance with IFRS.

On behalf of management,



Rupen Pandya

President and Chief Executive Officer
May 28, 2025



Troy King

Executive Vice-President, Chief Strategy,
Technology and Financial Officer

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

I, Rupen Pandya, President and Chief Executive Officer of Saskatchewan Power Corporation, and I, Troy King, Executive Vice-President, Chief Strategy, Technology and Financial Officer of Saskatchewan Power Corporation, certify the following:

- (a) That we have reviewed the consolidated financial statements included in the Annual Report of Saskatchewan Power Corporation. Based on our knowledge, having exercised reasonable diligence, the consolidated financial statements included in the Annual Report, fairly present, in all material respects the financial condition, results of operations, and cash flows, as at March 31, 2025.
- (b) That based on our knowledge, having exercised reasonable diligence, the consolidated financial statements included in the Annual Report of Saskatchewan Power Corporation do not contain any untrue statements of material fact, or omit to state a material fact that is either required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made.
- (c) That Saskatchewan Power Corporation is responsible for establishing and maintaining effective internal control over financial reporting, which includes safeguarding of assets and compliance with applicable legislative authorities; and Saskatchewan Power Corporation has designed internal controls over financial reporting that are appropriate to the circumstances of Saskatchewan Power Corporation.
- (d) That Saskatchewan Power Corporation conducted its assessment of the effectiveness of the Corporation's internal controls over financial reporting and, based on the results of this assessment, Saskatchewan Power Corporation can provide reasonable assurance that internal controls over financial reporting as at March 31, 2025, were operating effectively and no material weaknesses were found in the design or operation of the internal controls over financial reporting.

On behalf of management,



Rupen Pandya

President and Chief Executive Officer
May 28, 2025



Troy King

Executive Vice-President, Chief Strategy,
Technology and Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Members of the Legislative Assembly of Saskatchewan:

Opinion

We have audited the consolidated financial statements of Saskatchewan Power Corporation (the Corporation), which comprise the consolidated statement of financial position as at March 31, 2025, and the consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the financial statements).

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at March 31, 2025, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards (Canadian GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises the information, other than the financial statements and our auditor's report thereon, in the Annual Report.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained the Annual Report prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Corporation as a basis for forming an opinion on the financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

The logo for Deloitte LLP, featuring the word "Deloitte" in a stylized script font followed by "LLP" in a bold, sans-serif font.

Chartered Professional Accountants

May 28, 2025

Regina, Saskatchewan

CONSOLIDATED STATEMENT OF INCOME

(in millions)

For the year ended March 31	Notes	2025	2024
Revenue			
Saskatchewan electricity sales	4	\$ 3,110	\$ 3,096
Exports	5	28	129
Other revenue	6	116	154
Total revenue		3,254	3,379
Expense			
Fuel and purchased power	7	1,105	1,240
Operating, maintenance and administration	8	865	811
Depreciation and amortization	9	638	605
Finance charges	10	418	409
Taxes	11	100	92
Other expenses	12	52	38
Total expense		3,178	3,195
Net income		\$ 76	\$ 184

See accompanying notes

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in millions)

For the year ended March 31	Notes	2025	2024
Net income		\$ 76	\$ 184
Other comprehensive income (loss)			
Items that may be reclassified subsequently to net income:			
Derivatives designated as cash flow hedges:			
Natural gas hedges:			
Change in fair value during the period		4	(19)
Realized losses during the period		(30)	(24)
Reclassification to income		30	24
Debt instruments designated as fair value through other comprehensive income (FVOCI):			
Change in fair value during the period	17	25	(2)
Items that will not be reclassified to net income:			
Defined benefit pension plans:			
Net actuarial gains	32	3	66
		32	45
Total comprehensive income		\$ 108	\$ 229

See accompanying notes

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(in millions)

As at March 31	Notes	2025	2024
Assets			
Current assets			
Cash and cash equivalents		\$ 50	\$ 374
Accounts receivable and unbilled revenue		491	469
Inventory	13	418	362
Prepaid expenses		44	38
Risk management assets	25	7	6
		1,010	1,249
Property, plant and equipment	14	12,294	11,173
Right-of-use assets	15	551	414
Intangible assets	16	69	82
Debt retirement funds	17	931	799
Other assets		35	27
Total assets		\$ 14,890	\$ 13,744
Liabilities and equity			
Current liabilities			
Accounts payable and accrued liabilities		\$ 715	\$ 869
Accrued interest		90	82
Deferred revenue	18	33	17
Dividend payable		-	5
Risk management liabilities	25	14	23
Short-term advances	19	809	910
Current portion of long-term debt	20	200	200
Current portion of lease liabilities	21	42	55
		1,903	2,161
Long-term debt	20	8,268	7,447
Lease liabilities	21	942	795
Employee benefits	32	61	61
Provisions	22	655	327
Total liabilities		11,829	10,791
Equity			
Retained earnings		2,313	2,237
Accumulated other comprehensive income	23	155	123
Equity advances	24	593	593
Total equity		3,061	2,953
Total liabilities and equity		\$ 14,890	\$ 13,744

See accompanying notes

On behalf of the Board:



Bryan Leverick
Acting Chair



Shawn Grice
Director

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in millions)	Retained earnings	Accumulated other comprehensive income (loss)			Equity advances	Total
		Net gains (losses) on derivatives designated as cash flow hedges	Net gains (losses) on debt instruments designated as FVOCI	Net actuarial gains (losses) on defined benefit pension plans		
Equity						
Balance, April 1, 2023	\$ 2,071	\$ 2	\$ (52)	\$ 128	\$ 593	\$ 2,742
Net income	184	-	-	-	-	184
Other comprehensive income (loss)	-	(19)	(2)	66	-	45
Dividends	(18)	-	-	-	-	(18)
Balance, March 31, 2024	\$ 2,237	\$ (17)	\$ (54)	\$ 194	\$ 593	\$ 2,953
Net income	76	-	-	-	-	76
Other comprehensive income	-	4	25	3	-	32
Dividends	-	-	-	-	-	-
Balance, March 31, 2025	\$ 2,313	\$ (13)	\$ (29)	\$ 197	\$ 593	\$ 3,061

See accompanying notes

CONSOLIDATED STATEMENT OF CASH FLOWS

(in millions)

For the year ended March 31	Notes	2025	2024
Operating activities			
Net income		\$ 76	\$ 184
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation and amortization	9	638	605
Finance charges	10	418	409
Net losses on asset disposals and retirements	12	35	35
Unrealized market value adjustments		-	1
Reclassification of natural gas hedges transitional market value losses		(6)	(9)
Allowance for obsolescence		2	-
Natural gas inventory market revaluation		(1)	-
Net employee benefits paid		(3)	(4)
Environmental provisions		27	-
Environmental expenditures		(5)	(4)
Net change in non-cash working capital	29	1,181	1,217
Interest paid		(231)	(30)
Cash provided by operating activities		(469)	(436)
Investing activities		481	751
Property, plant and equipment additions		(1,364)	(1,090)
Intangible assets additions	16	(12)	(35)
Net costs of removal of assets		(15)	(8)
Cash used in investing activities		(1,391)	(1,133)
Decrease in cash before financing activities		(910)	(382)
Financing activities			
Net (repayments of) proceeds from short-term advances		(101)	120
Proceeds from long-term debt	20	1,021	732
Repayments of long-term debt	20	(200)	(150)
Debt retirement fund instalments	17	(75)	(70)
Principal repayment of lease liabilities		(54)	(55)
Dividends paid		(5)	(13)
Cash provided by financing activities		586	564
(Decrease) increase in cash		(324)	182
Cash and cash equivalents, beginning of year		374	192
Cash and cash equivalents, end of year		\$ 50	\$ 374

See accompanying notes

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF BUSINESS

Saskatchewan Power Corporation (SaskPower; the Corporation), a provincially-owned Crown corporation, generates, purchases, transmits, distributes and sells electricity and related products and services. Founded as the Saskatchewan Power Commission in 1929, SaskPower was set up in 1949 and operates primarily under the mandate and authority of *The Power Corporation Act*. SaskPower's head office is located at 2025 Victoria Avenue in Regina, Saskatchewan, Canada, S4P 0S1.

By virtue of *The Crown Corporations Act*, 1993, SaskPower has been designated a subsidiary of Crown Investments Corporation of Saskatchewan (CIC), a provincial Crown corporation. Accordingly, the financial results of the Corporation are included in the consolidated financial statements of CIC. As a provincial Crown corporation, the Corporation is not subject to federal and provincial income taxes.

NOTE 2 BASIS OF PREPARATION

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with IFRS® Accounting Standards as issued by the International Accounting Standards Board (IFRS). The consolidated financial statements were authorized for issue by the Board of Directors on May 28, 2025.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following material items in the consolidated statement of financial position:

- Inventory at lower of cost and net realizable value defined in Note 3(b).
- Provisions at discounted expected future cash flows defined in Note 3(g).
- Financial instruments that are accounted for according to the financial instrument categories defined in Note 3(m).
- Employee benefit plans recognized at the fair value of plan assets less the present value of the accrued benefit obligations defined in Note 3(n).

(c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest million.

(d) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Significant areas requiring the use of management estimates and judgments are further described in the following summary of material accounting policies and related notes:

(i) Saskatchewan electricity sales

Estimation and judgment are used to determine the amount of electricity deliveries not yet billed at period-end. Unbilled revenue is estimated by calculating the daily average revenue for each customer based on the customer's past consumption history multiplied by the number of days between the last billing date and the end of the period (Notes: 3(h)(i) and 4).

(ii) Customer contributions

Customer contributions are funds received from certain customers towards the costs of service extensions. In determining when to recognize revenue related to customer contributions, management is required to make judgments in regard to when the related property, plant and equipment is available for use and performance obligations are complete (Notes: 3(h)(iii) and 6).

(iii) Receivables

Management's best estimate is required to determine the amount of receivables that will be uncollectible in a given period. The expected credit loss allowance represents the expected credit losses on trade receivables which is based on a percentage of accounts outstanding (Notes: 3(m)(v) and 26).

(iv) Inventory

Estimation and judgment are used to determine the appropriate measure of net realizable value as well as the allowance for inventory obsolescence. Management's best estimate is required to determine the amount of inventories to be written off in a given period (Notes: 3(b) and 13).

(v) Property, plant and equipment and intangible assets

Estimation and judgment are involved in determining the useful lives, related depreciation and amortization and accumulated depreciation and amortization of property, plant and equipment and intangible assets. Estimated useful lives are determined based upon manufacturer's guidance on asset life, SaskPower's past experience with similar assets, industry averages, as well as expectations about future events that could impact the life of the asset. Estimated useful lives are reviewed annually to ensure their reasonableness (Notes: 3(c), 3(d), 3(e), 9, 14 and 16).

Judgment has been used to determine the estimated useful lives and related accelerated depreciation for coal-fired generation facility assets based on federal regulations.

(vi) Leases

In assessing the carrying amounts of right-of-use assets and lease liabilities and underlying estimates of future cash flows, management must use judgment in identifying which arrangements contain a lease as well as the lease term for contracts, including renewal options for which SaskPower is the lessee (Notes: 3(l), 15 and 21).

(vii) Provisions

Estimation and judgment are involved in determining the carrying amounts of decommissioning and environmental remediation provisions. The provisions are recorded at the fair value based on the Corporation's best estimate of the future cash expenditures required to settle the obligations, taking into account current environmental regulations. The underlying estimates of future cash flows are required to be made over a long period of time, given the fact that most provisions will not be settled for a number of years (Notes: 3(g) and 22).

(viii) Financial instruments

Determining the fair value of financial instruments and derivatives can require significant estimation regarding components such as future price, volatility, and liquidity. Fair values can fluctuate significantly depending on current market conditions. These estimates of fair value may not accurately reflect the amounts that could be realized or settled (Notes: 3(m) and 25).

(ix) Employee benefits

Employee benefit plan expense and obligations are calculated by an independent actuary based on underlying actuarial assumptions, including discount rates, inflation rates, future pension indexing and life expectancy. These assumptions are determined by management and reviewed annually by the actuary. The calculations are complex, and a change in the estimate of any of the assumptions could have a material effect on the employee benefit plan expense or obligation (Notes: 3(n) and 32).

(e) New standards, amendments and interpretations not yet adopted

New standards, amendments and interpretations which are not yet effective for the year ended March 31, 2025, have not been applied in preparing these consolidated financial statements. In particular, the Corporation is reviewing the following new and amended standards to determine the potential impact:

- Amendments to IFRS 9, *Financial Instruments*
- IFRS 18, *Presentation and Disclosure in Financial Statements*

NOTE 3 MATERIAL ACCOUNTING POLICIES

(a) Basis of consolidation

(i) Subsidiaries

The consolidated financial statements include the accounts of the Corporation and its wholly owned subsidiaries with all significant inter-company transactions and balances being eliminated.

Separate audited financial statements are prepared annually for its wholly owned subsidiary: NorthPoint Energy Solutions Incorporated (NorthPoint). NorthPoint trades electricity in markets outside of Saskatchewan.

A new wholly owned subsidiary, SaskNuclear Incorporated (SaskNuclear) was established on September 13, 2024. SaskNuclear is a holding company which has no active operations. As a result, no separate audited financials were prepared.

(ii) Joint operations

Joint operations are those entities over whose activities the Corporation has joint control, established by contractual agreement and requiring unanimous consent for strategic financial and operating decisions. They also provide the Corporation with rights to the assets and liabilities related to the arrangement.

The Corporation has classified the following arrangement as a joint operation:

- 50% ownership interest in BHP SaskPower Carbon Capture and Storage (CCS) Knowledge Centre Inc. This not-for-profit corporation was established on February 26, 2016, to advance the understanding and use of CCS as a means of managing greenhouse gas emissions and to further research projects related thereto as agreed upon by its members from time to time. The operations are funded by BHP Canada Inc. as per the sponsorship funding agreement which has been extended to December 31, 2026.

(b) Inventory

Maintenance materials, supplies, natural gas, coal and other fuel inventory are recorded at the lower of weighted average cost and net realizable value. Net realizable value represents the estimated selling price for inventories less all estimated costs necessary to make the sale. Replacement cost is used as management's best estimate of the net realizable value for maintenance materials, supplies, coal and other fuel inventory. Net realizable value for natural gas inventory is determined using the near-month Alberta natural gas market price. Inventories are written down to net realizable value on an item-by-item basis.

In establishing the appropriate provision for inventory obsolescence, management estimates the likelihood that inventory on hand will become obsolete due to changes in technology and regulations. Maintenance materials and supplies are charged to inventory when purchased and expensed or capitalized when used. Natural gas, coal and other fuel inventory are charged to inventory when purchased and expensed as consumed or sold (Note 13).

(c) Property, plant and equipment

Property, plant and equipment is recorded at cost or deemed cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, services and direct labour. Borrowing costs associated with major capital and development projects that are six months or longer in duration are capitalized during the construction period at the weighted average cost of borrowings. Assets under construction are recorded as in progress until they are operational and available for use.

Costs are capitalized provided there is reasonable certainty they will provide benefits into the future. Significant renewals and enhancements to existing assets are capitalized only if the useful life of the asset is increased; physical output, service capacity or quality is improved above original design standards; or operating costs are reduced by a substantial and quantifiable amount that can be reliably measured. The costs of day-to-day servicing of property, plant and equipment are expensed as incurred (Note 14).

When property, plant and equipment are disposed of or retired, the related costs less accumulated depreciation are derecognized. The gain or loss arising on the disposal or retirement of an item of property, plant and equipment is determined as the difference between the sales proceeds less costs of removal and the carrying amount of the asset. The gain or loss on asset disposals and retirements is recognized in profit or loss as other expenses (Note 12).

Assets held under right-of-use leases are initially recognized at the lower of their fair value at the inception of the lease or the present value of the minimum lease payments (Note 15). The corresponding liability is recorded as a lease liability (Note 21).

(d) Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each component of property, plant and equipment. Depreciation commences when the property, plant and equipment is ready for its intended use. Land is not depreciated.

The estimated useful life of property, plant and equipment is based on manufacturer's guidance, past experience and future expectations regarding the potential for technical obsolescence. Their estimated useful lives are reviewed annually and any changes are applied prospectively.

The estimated useful lives of the major classes of property, plant and equipment are:

Asset class	Estimated useful lives (years)
Generation	3-110
Transmission	3-55
Distribution	3-40
Other	4-60

A one-year decrease in the estimated useful life of each of the major classes of property, plant and equipment would result in a \$34 million increase to depreciation expense annually.

Assets held under right-of-use leases are depreciated over their expected useful economic lives on the same basis as for owned assets, or where shorter, the lease term (Note 9).

(e) Intangible assets

The Corporation's only identifiable intangible asset is software. Software is recorded at cost less accumulated amortization and accumulated impairment losses. Software costs include the cost of externally purchased software packages and for internally developed programs, related external and direct labour costs. Software development costs are capitalized when it is probable that the expected future economic benefits attributable to the asset will flow to the Corporation and the cost can be measured reliably (Note 16). Certain implementation costs relating to cloud computing arrangements and maintenance of existing software programs that do not meet the capitalization criteria are expensed as incurred in operating, maintenance and administration (OM&A) expense.

Amortization is calculated on a straight-line basis over five to ten years — the estimated useful life of the Corporation's software programs. The estimated useful life of intangible assets is reviewed annually and any changes are applied prospectively (Note 9).

(f) Impairment of assets

At each reporting date, the Corporation evaluates its property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be fully recoverable. Factors which could indicate an impairment exists include significant changes in the Corporation's strategy or underperformance of assets relative to projected future operating results. An impairment is recognized when the carrying amount of an asset or cash generating unit (CGU) exceeds the recoverable amount. The recoverable amount is the higher of the fair value less costs to sell and the present value of the future cash flows to be derived from a CGU.

Impairment losses previously recognized for an asset are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. In no case shall the revised carrying amount exceed the original carrying amount, after depreciation or amortization, that would have been determined if no impairment loss had been recognized. An impairment loss or reversal of an impairment loss is recognized in other expenses.

As at March 31, 2025, the Corporation determined that there were no impairment losses or reversal of impairment losses to be recognized related to its long-lived assets.

(g) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation, the timing or amount of which is uncertain. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. For SaskPower, that rate is considered to be equal to the spot rate derived from yields on Government of Saskatchewan bonds using a rate term that matches the timing of the expected cash flows. The unwinding of the discount on provisions is recognized in profit or loss as finance expense.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

(i) Decommissioning

A decommissioning provision is a legal or constructive obligation associated with the decommissioning of a long-lived asset. The Corporation recognizes decommissioning provisions in the period they are incurred if a reasonable estimate of fair value (net present value) can be determined. The Corporation recognizes provisions to decommission coal, natural gas, cogeneration, wind generation facilities and other properties typically in the period in which the facility is commissioned.

The fair value of the estimated decommissioning costs is recorded as a provision with an offsetting amount capitalized and included as part of property, plant and equipment. The provisions are increased periodically for the passage of time by calculating interest expense. The offsetting capitalized asset retirement costs are depreciated over the estimated useful life of the related asset. The calculations of fair value are based on detailed studies that take into account various assumptions regarding the anticipated future cash flows including the method and timing of decommissioning and estimates of future inflation rates. Decommissioning provisions are periodically reviewed and any changes in the estimated timing and amount of future cash flows, as well as changes in the discount rate, are recognized as an increase or decrease in the carrying amount of the obligation and the related asset. If the asset value is fully depreciated the changes are recognized in profit or loss as other expenses (Notes: 12 and 22).

(ii) Environmental remediation

A provision for environmental remediation is accrued when the occurrence of an environmental expenditure, related to present or past activities of the Corporation, is considered probable and the costs of remedial activities can be reasonably estimated. The fair value of the estimated costs for investigations and remediation at identified sites is recorded as a provision in profit or loss as other expenses. These provisions are based on management's best estimate considering current environmental laws and regulations and are recorded at fair value. The Corporation reviews its estimates of future environmental expenditures on an ongoing basis. Changes in the estimated timing and amount of future cash flows are recognized in profit or loss as other expenses (Notes: 12 and 22).

(h) Revenue recognition

The majority of the Corporation's revenue from contracts with customers is derived from the generation, transmission, distribution, purchase and sale of electricity and related products and services under *The Power Corporation Act*. The Corporation evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is also recognized when control over a promised good or service is transferred to the customer and the Corporation is entitled to consideration as a result of completion of the performance obligation.

A contract liability (deferred revenue) is recorded when the Corporation receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Corporation has rights to consideration for the completion of a performance obligation when that right is conditional on something other than the passage of time. The Corporation recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

Significant judgment may be required to identify the number of distinct performance obligations within a contract and the allocation of the transaction price to multiple performance obligations in a contract, and to determine when performance obligations have been satisfied.

The Corporation's main sources of revenue and method applied to the recognition of this revenue in these consolidated financial statements are as follows:

(i) Saskatchewan electricity sales

Electricity sales contracts are deemed to have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. These performance obligations are considered to be satisfied over time as electricity is delivered because of the continuous transfer of control to the customer. The method of revenue recognition for the electricity is an output method, which is based on the volume delivered to the customer.

Saskatchewan electricity sales are calculated based on the customer's usage of electricity during the period at the applicable published rates for each customer class. Electricity rates in Saskatchewan are subject to review by the Saskatchewan Rate Review Panel with final approval by provincial cabinet. Saskatchewan electricity sales include an estimate of electricity deliveries not yet billed at period-end. The estimated unbilled revenue is based on several factors, including estimated consumption by customer, applicable customer rates and the number of days between the last billing date and the end of the period (Note 4).

(ii) Exports

Export sales are recognized upon delivery to the customer and include an estimate of electricity deliveries not yet billed at period end (Note 5).

(iii) Customer contributions

Customer contributions are funds received from certain customers toward the costs of service extensions. Customer contribution contracts are deemed to have a single performance obligation. These performance obligations are satisfied at a point in time and recognized in profit or loss as other revenue when the related property, plant and equipment is available for its intended use. The transaction price is the estimated construction charge for connecting the customer to the network (Note 6).

(iv) Other

Other revenue includes fly ash and carbon dioxide (CO₂) sales which are recorded upon delivery of the related good or service (Note 6).

(i) Government grants

Government grants are recognized when there is reasonable assurance that they will be received and the Corporation will comply with the conditions associated with the grant. Grant funding that compensates the Corporation for expenses incurred is recognized in profit or loss as an offset against fuel and purchased power or OM&A costs in the same period in which the expenses are recognized. Grant funding that compensates the Corporation for the cost of an asset is netted against the capitalized asset costs and recognized in profit or loss over the estimated useful life of the asset.

(j) Finance charges

Finance expense is comprised of interest expense on short-term and long-term borrowings, finance costs related to lease liabilities, interest on employee benefit plans, and interest on provisions. Interest expense is recognized in profit or loss, using the effective interest method. Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as a finance expense as the costs accrue (Note 10).

Finance income is comprised of earnings on debt retirement funds and interest. Finance income is recognized in profit or loss as earned (Note 10).

(k) Foreign currency translation

Monetary assets and liabilities denominated in a foreign currency are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses are translated at the rate prevailing at the transaction date. Foreign currency translation gains and losses are included in other expenses in the period in which they arise.

(l) Leases

A contract is or contains a lease if the contract conveys a right to control the use of an identified asset for a period of time in exchange for consideration. The Corporation has assessed its arrangements to determine whether they contain a lease. Certain take-or-pay power purchase agreements (PPAs) relating to the Meridian Cogeneration Station, Spy Hill Generating Station and the North Battleford Generating Station gas-fired facilities which, in management's judgment, give SaskPower the exclusive right to use specific production assets, meet the definition of a lease.

Right-of-use assets are initially measured at an amount equal to the lease liability and are adjusted for any payments made at or before the commencement date, less any lease incentives received. Right-of-use assets are depreciated over the related lease term. The Corporation has applied judgment to determine the lease term for contracts that include renewal options. The assessment of whether the Corporation is reasonably certain to exercise such options impacts the lease term, which significantly affects the amount of lease liabilities and right-of-use assets recognized (Notes: 9 and 15).

The corresponding lease liability is measured at the present value of the lease payments that are not paid at commencement and are discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. Each lease payment is allocated between the liability and interest so as to achieve a constant rate on the finance balance outstanding. The interest component is included in finance expense. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation's estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the right-of-use asset or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero (Notes: 10 and 21).

Payments for short-term and low-value leases are recognized as an operating expense. Variable lease payments that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset and are recognized as an expense in the period in which the event or condition that triggers the payment occurs.

(m) Financial instruments

(i) Classification and measurement

SaskPower classifies its financial instruments into one of the following categories: amortized cost (AC); fair value through other comprehensive income (FVOCI); or fair value through profit or loss (FVTPL) (Note 25).

All financial instruments are measured at fair value on initial recognition and recorded on the consolidated statement of financial position. Financial assets and liabilities are offset and the net amount is reported on the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously. Transaction costs that are directly attributable to the acquisition or issue of financial assets and liabilities (other than financial assets and liabilities at FVOCI or FVTPL) are added to or deducted from the fair value of the financial assets or liabilities, as appropriate, on initial recognition.

Transactions costs directly attributable to the acquisition of financial instruments classified as FVOCI or FVTPL are expensed as incurred. Measurement in subsequent periods depends on the classification of the financial instrument.

Financial assets and liabilities classified as amortized cost are subsequently measured at amortized costs using the effective interest method less any impairment. Financial instruments classified as FVOCI are subsequently measured at fair value, with changes in fair value recognized in other comprehensive income (loss). Financial instruments classified as FVTPL are subsequently measured at fair value with changes in fair value recognized in profit or loss. Any interest income, foreign exchange gains and losses, impairment or gains or losses on derecognition are recognized in the consolidated statement of income. On derecognition, gains and losses accumulated in other comprehensive income (loss) are reclassified to the consolidated statement of income.

SaskPower classifies its debt retirement funds as debt instruments designated as FVOCI as the following conditions are met:

- The debt retirement funds are administered by the Government of Saskatchewan Ministry of Finance whose business model objective is to both hold underlying investments to collect contractual cash flows and to sell; and
- The contractual terms of the debt retirement funds give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Derivative financial instruments that are held-for-trading, including natural gas contracts, are recognized as a financial asset or a financial liability on the trade date. All derivative financial instruments are classified as FVTPL and recorded at fair value on the consolidated statement of financial position as risk management assets and liabilities. If there is a difference between the fair value at initial recognition and the transaction price, the day one gain is deferred and amortized into profit or loss over the term of the contract. Subsequent changes in the fair value of these derivative financial instruments, with the exception of the effective portion of derivatives designated as cash flow hedges, are recognized in profit or loss. Refer to Note 3(m)(ii) for derivatives designated as hedging instruments.

Certain commodity contracts for the physical purchase of natural gas and electricity qualify as own-use contracts. SaskPower entered into these contracts for the purpose of physical receipt of the natural gas or electricity in accordance with its own expected usage requirements for the generation of electricity and servicing of Saskatchewan customers. As such, these non-financial derivative contracts are not recorded at fair value on the consolidated statement of financial position; rather, the contracts are accounted for as a purchase at the time of delivery.

The terms and conditions of certain financial and non-financial derivative financial instrument contracts require SaskPower to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of exposure limits granted. When posted, these collateral amounts are recognized as margin deposits on derivative contracts and are included with accounts receivable on the consolidated statement of financial position.

(ii) Hedges

In order to qualify for hedge accounting, the Corporation designates derivatives as hedges through formal documentation of all relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking the hedge transaction. This process includes linking derivatives to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Corporation formally assesses both at the hedge's inception and on an ongoing basis whether the derivatives used are highly effective in offsetting changes in cash flows of the hedged item and the timing of the cash flows is similar.

The Corporation enters into forward contracts to hedge exposures to anticipated changes in commodity prices on forecasted natural gas purchases related to the Corporation's PPAs. In the past, the Corporation entered into bond forward agreements to hedge exposures to anticipated changes in interest rates on forecasted issuances of debt (Note 25). The Corporation chooses to designate these contracts as cash flow hedges. The Corporation assesses whether the derivative designated in each hedging relationship is expected to be effective in offsetting changes in cash flows of the hedged item using the hypothetical derivative method. The Corporation applies a hedge ratio of 1:1. As such, the effective portion of the changes in fair value related to the derivative financial instruments are recognized in other comprehensive income (loss), with the fair value being recognized as risk management assets and liabilities on the consolidated statement of financial position. Ineffective portions of hedges are recorded in profit or loss immediately. When the natural gas forward agreements are settled, the resulting gain or loss recorded in accumulated other comprehensive income (loss) is recognized in fuel and purchased power immediately. The bond forward agreements expired upon the issuance of debt, therefore, the resulting gain or loss recorded in accumulated other comprehensive income (loss) is being amortized to finance charges over the term of the debt.

(iii) Embedded derivatives

As at March 31, 2025, the Corporation does not have any outstanding contracts or financial instruments with embedded derivatives that are required to be valued separately.

(iv) Fair value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal or most advantageous market at the measurement date. SaskPower's own credit risk and the credit risk of the counterparty have been taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The Corporation has classified the fair value of its financial instruments as level 1, 2, or 3 (Note 25) as defined below:

Level 1 Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities to which the Corporation has immediate access.

Level 2 Fair values are determined using inputs other than quoted prices included in level 1 that are observable for the asset or liability, either directly or indirectly. The debt retirement funds are valued by the Government of Saskatchewan Ministry of Finance using information provided by investment dealers. To the extent possible, valuations reflect indicative secondary pricing for these securities. In all other circumstances, valuations are determined with reference to similar actively traded instruments. The fair value of long-term debt is determined by the present value of future cash flows, discounted at the market rate of interest for the same or similar debt instruments.

Natural gas contract fair values are determined using independent pricing information from external market providers. The contracted cash flows are discounted using observable yield curves.

Level 3 Fair values are determined based on inputs for the asset or liability that are not based on observable market data. As at March 31, 2025, the Corporation does not have any financial instruments classified as level 3.

(v) Impairment of financial assets

The Corporation recognizes loss allowances for expected credit losses (ECLs) on financial assets measured at amortized cost and debt instruments designated as FVOCI. The Corporation measures loss allowances for trade receivables at an amount equal to lifetime ECL. Debt instruments and other receivables that are determined to have low credit risk at the reporting date are measured at 12-month ECL. The Corporation considers a debt instrument to have low credit risk when its credit risk rating is A or higher (investment grade).

When determining whether the credit risk of a financial asset has increased, the Corporation performs a quantitative and qualitative analysis based on the Corporation's historical experience and forward-looking information. The Corporation assumes that the credit risk on a financial asset has increased significantly if it is more than 30 days past due. The Corporation considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to the Corporation in full without recourse by the Corporation to actions such as realizing security, or the financial asset is 90 days or more past due.

Credit loss allowances for financial assets measured at amortized cost are deducted from the gross carrying amount of the assets. For debt instruments at FVOCI, the credit loss allowance is charged to profit or loss and is recognized in other comprehensive income (loss). The gross carrying amount of a financial asset is written off to the extent that there is no realistic prospect of recovery (Note 26).

(n) Employee benefits

The Corporation has a defined contribution pension plan, defined benefit pension plans, and other benefit plans that provide retirement benefits for its employees.

(i) Defined contribution pension plan

A defined contribution pension plan is a post-employment benefit under which SaskPower pays fixed contributions into a separate entity and has no legal or constructive obligation to pay further amounts. Obligations for contributions to the defined contribution pension plan are recognized in OM&A expense in the period during which services are rendered by employees (Note 32).

(ii) Defined benefit pension plans

A defined benefit pension plan is a post-employment benefit plan other than a defined contribution pension plan. The Corporation's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for service in the current and prior periods. The obligation is discounted to determine its present value. The discount rate is the yield at the reporting date on high quality bonds that match the timing of expected benefit payments. The fair value of plan assets is deducted from the present value of the defined benefit obligation to determine the plan surplus or deficit. The calculation is performed by a qualified actuary using the projected unit credit method. When the calculation results in a benefit to the Corporation, the recognized asset is limited to the lower of the plan surplus and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Corporation if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Current service costs are recognized in profit or loss as OM&A expense. Interest expense (income) is calculated by applying the discount rate to the net accrued benefit obligation and recognized as finance charges. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

The Corporation recognizes all actuarial gains and losses arising from defined benefit plans directly in other comprehensive income (loss) in the period in which they arise (Note 32).

(iii) Other benefit plans

The Corporation provides a supplementary superannuation plan for certain management employees who elect to forgo their entitlement to banked days off. SaskPower's current period expense is limited to yearly notional contributions to the plan based upon the employee's salary and an amount allocated for interest on the employee's plan balance.

The Corporation also provides lifetime superannuation allowances and bridge allowances to employees who chose to retire under various early retirement options. The cost of these benefits is actuarially determined by calculating the present value of all future benefit entitlements (Note 32).

NOTE 4 SASKATCHEWAN ELECTRICITY SALES

(in millions)

For the year ended March 31	2025	2024
Residential	\$ 637	\$ 632
Farm	188	198
Commercial	557	557
Oilfield	477	469
Power	879	895
Reseller	104	105
Federal carbon charge collected	268	240
	\$ 3,110	\$ 3,096

NOTE 5 EXPORTS

(in millions)

For the year ended March 31	2025	2024
Domestic	\$ 13	\$ 62
Foreign	15	67
	\$ 28	\$ 129

NOTE 6 OTHER REVENUE

(in millions)

For the year ended March 31	2025	2024
Customer contributions	\$ 58	\$ 90
CO ₂ sales	19	26
Fly ash sales	13	11
Late payment charges	7	7
Joint use charge	6	6
Custom work	5	4
Miscellaneous revenue	8	10
	\$ 116	\$ 154

NOTE 7 FUEL AND PURCHASED POWER

(in millions)

For the year ended March 31	2025	2024
Gas	\$ 316	\$ 366
Coal	313	296
Imports	173	178
Wind	108	84
Hydro	18	16
Solar	8	6
Other	25	25
Federal carbon charge	280	269
Grant funding	(136)	-
	\$ 1,105	\$ 1,240

Gas costs include the fuel charges associated with the electricity generated from SaskPower-owned gas-fired facilities as well as gas-fired PPA facilities. Imports represent electricity purchased from suppliers that produce power outside Saskatchewan. Wind, solar and other includes the cost of electricity obtained through PPA facilities, small independent power producers, and the cost of demand response programs.

NOTE 8 OPERATING, MAINTENANCE AND ADMINISTRATION

(in millions)

For the year ended March 31	Notes	2025	2024
Salaries and benefits		\$ 430	\$ 391
Employee long-term benefits	32	35	31
External services		297	273
Materials and supplies		53	50
Other		86	88
Grant funding		(36)	(22)
		\$ 865	\$ 811

NOTE 9 DEPRECIATION AND AMORTIZATION

(in millions)

For the year ended March 31	Notes	2025	2024
Depreciation of property, plant and equipment	14	\$ 562	\$ 529
Depreciation of right-of-use assets	15	51	51
Amortization of intangible assets	16	25	25
		\$ 638	\$ 605

NOTE 10 FINANCE CHARGES

(in millions)

For the year ended March 31	Notes	2025	2024
Finance expense			
Interest on long-term debt		\$ 326	\$ 286
Interest on lease liabilities		131	132
Interest on short-term advances		27	33
Net interest on employee benefit plans	32	6	8
Interest on provisions	22	14	11
Other interest and charges		1	1
		505	471
Less: interest capitalized		(47)	(39)
amortization of debt premiums net of discounts	20	-	(3)
		458	429
Finance income			
Debt retirement fund earnings	17	(32)	(14)
Interest income		(8)	(6)
		(40)	(20)
		\$ 418	\$ 409

NOTE 11 TAXES

(in millions)

For the year ended March 31	2025	2024
Saskatchewan corporate capital tax	\$ 64	\$ 57
Grants-in-lieu	35	34
Miscellaneous tax expense	1	1
	\$ 100	\$ 92

NOTE 12 OTHER EXPENSES

(in millions)

For the year ended March 31	2025	2024
Net losses on asset disposals and retirements	\$ 35	\$ 35
Inventory variance adjustments	9	-
Other environmental costs	4	3
Decommissioning provisions	3	-
Settlement claims	1	-
	\$ 52	\$ 38

NOTE 13 INVENTORY

(in millions)

As at March 31	2025	2024
Maintenance materials and supplies	\$ 417	\$ 361
Allowance for obsolescence	(21)	(19)
	396	342
Natural gas	9	8
Coal	14	13
Other fuel	1	2
	420	365
Natural gas market revaluation	(2)	(3)
	\$ 418	\$ 362

(in millions)

For the year ended March 31	2025	2024
Inventory consumed during the period:		
Maintenance materials and supplies	\$ 304	\$ 278
Natural gas	165	205
Coal	193	210
Other fuel	4	4
	\$ 666	\$ 697

(in millions)

	Allowance for obsolescence
Balance, April 1, 2023	\$ 19
Provision for obsolete inventory	2
Inventory disposals and/or write-downs	(2)
Balance, March 31, 2024	\$ 19
Provision for obsolete inventory	5
Inventory disposals and/or write-downs	(3)
Balance, March 31, 2025	\$ 21

NOTE 14 PROPERTY, PLANT AND EQUIPMENT

(in millions)

	Generation	Transmission	Distribution	Other	Construction in progress	Total
Cost or deemed cost						
Balance, April 1, 2023	\$ 7,843	\$ 3,084	\$ 5,126	\$ 1,150	\$ 1,117	\$ 18,320
Additions	109	217	337	288	1,213	2,164
Grant funding	-	-	-	-	(49)	(49)
Disposals and/or retirements	(27)	(10)	(73)	(35)	-	(145)
Transfers/adjustments	(18)	-	(2)	(1)	(986)	(1,007)
Balance, March 31, 2024	\$ 7,907	\$ 3,291	\$ 5,388	\$ 1,402	\$ 1,295	\$ 19,283
Additions	822	114	375	80	1,497	2,888
Grant funding	-	-	-	-	(74)	(74)
Disposals and/or retirements	(26)	(2)	(117)	(185)	-	(330)
Transfers/adjustments	291	-	-	1	(1,403)	(1,111)
Balance, March 31, 2025	\$ 8,994	\$ 3,403	\$ 5,646	\$ 1,298	\$ 1,315	\$ 20,656

Accumulated depreciation						
Balance, April 1, 2023	\$ 4,117	\$ 931	\$ 2,077	\$ 574	\$ -	\$ 7,699
Depreciation expense	250	78	143	58	-	529
Disposals and/or retirements	(22)	(3)	(61)	(32)	-	(118)
Balance, March 31, 2024	\$ 4,345	\$ 1,006	\$ 2,159	\$ 600	\$ -	\$ 8,110
Depreciation expense	299	80	119	64	-	562
Disposals and/or retirements	(45)	(1)	(81)	(183)	-	(310)
Balance, March 31, 2025	\$ 4,599	\$ 1,085	\$ 2,197	\$ 481	\$ -	\$ 8,362

Net book value						
Balance, April 1, 2023	\$ 3,726	\$ 2,153	\$ 3,049	\$ 576	\$ 1,117	\$ 10,621
Balance, March 31, 2024	\$ 3,562	\$ 2,285	\$ 3,229	\$ 802	\$ 1,295	\$ 11,173
Balance, March 31, 2025	\$ 4,395	\$ 2,318	\$ 3,449	\$ 817	\$ 1,315	\$ 12,294

For the year ended March 31, 2025, \$47 million (2024 – \$39 million) of interest costs were capitalized at the weighted average cost of borrowings rate of 4.00% (2024 – 3.80%).

NOTE 15 RIGHT-OF-USE ASSETS

(in millions)

	Power purchase agreements	Buildings	Land	Total
Cost				
Balance, April 1, 2023	\$ 1,017	\$ 12	\$ 7	\$ 1,036
Additions and/or modifications	-	-	2	2
Terminations	-	(5)	-	(5)
Balance, March 31, 2024	\$ 1,017	\$ 7	\$ 9	\$ 1,033
Additions and/or modifications	187	1	-	188
Terminations	-	(2)	-	(2)
Balance, March 31, 2025	\$ 1,204	\$ 6	\$ 9	\$ 1,219
Accumulated depreciation				
Balance, April 1, 2023	\$ 563	\$ 7	\$ 3	\$ 573
Depreciation expense	48	2	1	51
Terminations	-	(5)	-	(5)
Balance, March 31, 2024	\$ 611	\$ 4	\$ 4	\$ 619
Depreciation expense	49	1	1	51
Terminations	-	(2)	-	(2)
Balance, March 31, 2025	\$ 660	\$ 3	\$ 5	\$ 668
Net book value				
Balance, April 1, 2023	\$ 454	\$ 5	\$ 4	\$ 463
Balance, March 31, 2024	\$ 406	\$ 3	\$ 5	\$ 414
Balance, March 31, 2025	\$ 544	\$ 3	\$ 4	\$ 551

NOTE 16 INTANGIBLE ASSETS

(in millions)

	Software
Cost	
Balance, April 1, 2023	\$ 412
Additions	35
Disposals and/or retirements	(145)
Balance, March 31, 2024	\$ 302
Additions	12
Disposals and/or retirements	(40)
Balance, March 31, 2025	\$ 274
Accumulated amortization	
Balance, April 1, 2023	\$ 340
Amortization expense	25
Disposals and/or retirements	(145)
Balance, March 31, 2024	\$ 220
Amortization expense	25
Disposals and/or retirements	(40)
Balance, March 31, 2025	\$ 205
Net book value	
Balance, April 1, 2023	\$ 72
Balance, March 31, 2024	\$ 82
Balance, March 31, 2025	\$ 69

NOTE 17 DEBT RETIREMENT FUNDS

(in millions)

Balance, April 1, 2023	\$	717
Debt retirement fund instalments		70
Debt retirement fund earnings		14
Debt retirement fund unrealized market value losses		(2)
Balance, March 31, 2024	\$	799
Debt retirement fund instalments		75
Debt retirement fund earnings		32
Debt retirement fund unrealized market value gains		25
Balance, March 31, 2025	\$	931

Under conditions attached to certain advances from the Government of Saskatchewan's General Revenue Fund, the Corporation is required to pay annually into debt retirement funds administered by the Government of Saskatchewan Ministry of Finance, amounts at least equal to 1% of the face value of certain debt outstanding. As at March 31, 2025, scheduled debt retirement fund instalments for the next five years are as follows:

(in millions)

For the year ended March 31	2026	2027	2028	2029	2030
Debt retirement fund instalments	\$ 85	\$ 84	\$ 84	\$ 81	\$ 79

NOTE 18 DEFERRED REVENUE

(in millions)

Balance, April 1, 2023	\$	44
Additions		20
Recognized in revenue		(47)
Balance, March 31, 2024	\$	17
Additions		25
Recognized in revenue		(9)
Balance, March 31, 2025	\$	33

Deferred revenue primarily relates to advance consideration received for customer contribution contracts. The related customer contribution revenue is recognized when the property, plant and equipment is available for its intended use.

NOTE 19 SHORT-TERM ADVANCES

(in millions)

As at March 31	2025	2024
Short-term advances	\$ 809	\$ 910

The short-term advances are due to the Government of Saskatchewan's General Revenue Fund. As at March 31, 2025, the advances have interest rates ranging from 2.62% to 3.13% and mature between April 3, 2025, and June 26, 2025. As at March 31, 2024, the advances had interest rates ranging from 4.94% to 5.79% and matured between April 4, 2024, and July 23, 2024.

NOTE 20 LONG-TERM DEBT

(in millions)

Balance, April 1, 2023	\$ 7,068
Long-term debt issues	732
Long-term debt repayments	(150)
Amortization of debt premiums net of discounts	(3)
Balance, March 31, 2024	\$ 7,647
Long-term debt issues	1,021
Long-term debt repayments	(200)
Amortization of debt premiums net of discounts	-
	\$ 8,468
Less: current portion of long-term debt	(200)
Balance, March 31, 2025	\$ 8,268

As at March 31, 2025, scheduled principal debt retirement requirements for the next five years are as follows:

(in millions)

For the year ended March 31	2026	2027	2028	2029	2030
Long-term debt repayments	\$ 200	\$ -	\$ 300	\$ 175	\$ -

Under conditions attached to certain advances from the Government of Saskatchewan's General Revenue Fund, the Corporation is required to pay annually into debt retirement funds administered by the Government of Saskatchewan Ministry of Finance, amounts at least equal to 1% of the face value of certain debt outstanding (Note 17).

Advances from the Government of Saskatchewan's General Revenue Fund (in millions):

Date of issue	Date of maturity	Effective interest rate (%)	Coupon rate (%)	Par value	Unamortized premiums (discounts)	Outstanding amount
May 30, 1995	May 30, 2025	8.82	8.75	\$ 100	\$ -	\$ 100
July 27, 2020	September 2, 2025	0.93	0.80	100	-	100
May 12, 2023	June 2, 2027	3.41	3.41	300	-	300
June 14, 2019	December 2, 2028	2.34	3.05	175	4	179
June 25, 2020	June 2, 2030	1.53	2.20	100	3	103
November 4, 2022	June 2, 2031	4.18	4.18	350	-	350
August 8, 2001	September 5, 2031	6.49	6.40	200	(1)	199
January 15, 2003	September 5, 2031	5.91	6.40	100	3	103
April 17, 2024	June 2, 2033	4.50	3.90	285	(12)	273
May 12, 2003	September 5, 2033	5.90	5.80	100	(1)	99
January 14, 2004	September 5, 2033	5.68	5.80	200	2	202
October 5, 2004	September 5, 2035	5.50	5.60	200	2	202
February 15, 2005	March 5, 2037	5.09	5.00	150	(1)	149
May 6, 2005	March 5, 2037	5.07	5.00	150	(1)	149
February 24, 2006	March 5, 2037	4.71	5.00	100	2	102
March 6, 2007	June 1, 2040	4.49	4.75	100	3	103
April 2, 2008	June 1, 2040	4.67	4.75	250	2	252
December 19, 2008	June 1, 2040	4.71	4.71	100	-	100
September 8, 2010	June 1, 2040	4.27	4.75	200	10	210
November 15, 2012	February 3, 2042	3.22	3.40	200	5	205
February 28, 2013	February 3, 2042	3.54	3.40	200	(3)	197
October 9, 2013	June 2, 2045	3.97	3.90	400	(4)	396
January 17, 2014	June 2, 2045	3.95	3.90	200	(1)	199
October 9, 2014	June 2, 2045	3.43	3.90	200	14	214
February 13, 2015	June 2, 2045	2.73	3.90	200	36	236
June 2, 2015	December 2, 2046	3.15	2.75	200	(13)	187
October 26, 2015	December 2, 2046	3.43	2.75	200	(21)	179
January 28, 2016	December 2, 2046	3.34	2.75	200	(18)	182
July 19, 2016	December 2, 2046	2.85	2.75	150	(2)	148
October 20, 2016	December 2, 2046	3.00	2.75	200	(8)	192
January 24, 2017	June 2, 2048	3.35	3.30	200	(2)	198
August 15, 2018	June 2, 2050	3.18	3.10	200	(3)	197
April 2, 2019	June 2, 2050	2.81	3.10	150	8	158
May 12, 2022	December 2, 2052	4.09	2.80	180	(38)	142
June 23, 2022	December 2, 2052	4.29	2.80	300	(72)	228
March 13, 2014	March 5, 2054	3.76	3.75	100	-	100
May 12, 2014	March 5, 2054	3.71	3.75	175	1	176
August 29, 2017	March 5, 2054	3.19	3.75	150	16	166
June 22, 2023	December 2, 2054	4.28	4.20	145	(2)	143
March 22, 2024	December 2, 2054	4.41	4.20	300	(10)	290
June 6, 2024	December 2, 2054	4.32	4.20	250	(5)	245
August 12, 2024	December 2, 2054	4.23	4.20	250	(1)	249
December 2, 2024	December 2, 2054	4.10	4.20	250	4	254
September 19, 2018	June 2, 2058	3.13	2.95	200	(7)	193
January 18, 2023	June 2, 2062	3.85	3.80	120	(1)	119
				\$ 8,580	\$ (112)	\$ 8,468

NOTE 21 LEASE LIABILITIES

(in millions)

As at March 31	2025	2024
Total future minimum lease payments	\$ 1,906	\$ 1,633
Less: future finance charges on leases	(922)	(783)
Present value of lease liabilities	984	850
Less: current portion of lease liabilities	(42)	(55)
	\$ 942	\$ 795

The above lease liabilities include PPAs relating to the Meridian Cogeneration Station, Spy Hill Generating Station and the North Battleford Generating Station gas-fired facilities as well as land and building leases. The weighted average discount rate applied to the PPA leases for the year ended March 31, 2025, is 13.79% (2024 – 15.07%) based on the rate implicit in these agreements, while the weighted average discount rate applied to land and building leases is 3.06% (2024 – 2.69%) based on the Corporation's incremental borrowing rate.

As at March 31, 2025, scheduled future minimum lease payments and the present value of lease liabilities are as follows:

(in millions)

	1 year	2-5 years	More than 5 years
Future minimum lease payments	\$ 174	\$ 726	\$ 1,006
Present value of lease liabilities	42	280	662

NOTE 22 PROVISIONS

(in millions)

	Decommissioning	Environmental remediation	Total
Balance, April 1, 2023	\$ 275	\$ 66	\$ 341
Charged to income:			
New obligations	3	-	3
Change in assumptions	(3)	-	(3)
Interest	11	-	11
Capitalized to property, plant and equipment:			
Reversed obligations	(2)	-	(2)
Change in assumptions	(19)	-	(19)
Settled during the period	(4)	-	(4)
Balance, March 31, 2024	\$ 261	\$ 66	\$ 327
Charged to income:			
New obligations ¹	-	24	24
Change in assumptions	3	-	3
Interest	14	-	14
Capitalized to property, plant and equipment:			
New obligations ²	341	-	341
Change in assumptions ²	(49)	-	(49)
Settled during the period	(5)	-	(5)
Balance, March 31, 2025	\$ 565	\$ 90	\$ 655

1. Included in the environmental remediation provisions is the cost of coal reclamation services which has been charged to fuel and purchased power costs. As per the coal agreement signed in 2024-25, SaskPower has agreed to reimburse third-party reclamation service costs required on mined lands.
2. In 2024-25, SaskPower engaged a third-party consultant to review its decommissioning and reclamation plans for its coal and natural gas facilities. As a result of the review, it was determined that the estimated amount of future cash flows required to settle these liabilities should be increased. This change in estimate was recognized as an increase in the carrying amount of the decommissioning provision and the related generation asset.

Assumptions

The significant assumptions adopted in measuring the Corporation's decommissioning provisions are:

As at March 31	2025	2024
Discount rate, end of period	2.63 - 4.51%	3.90 - 4.58%
Long-term inflation rate	2.00%	2.00%
Undiscounted cash flows (in millions)	\$ 1,271	\$ 522

Discount rates based on the Government of Saskatchewan bond yields were used to calculate the carrying values of the provisions. The costs of the decommissioning provisions will be incurred between fiscal 2026 and 2053. No funds have been set aside by the Corporation to settle the decommissioning provisions.

Sensitivity of assumptions

Sensitivity of provisions to changes in the discount rate and inflation rate on the recorded liability as at March 31, 2025, is as follows:

(in millions)

	Decommissioning provisions	
	0.5% increase	0.5% decrease
Discount rate	\$ (46)	\$ 51
Inflation rate	56	(50)

NOTE 23 ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

As at March 31	2025	2024
Realized losses on derivatives designated as cash flow hedges	\$ (9)	\$ (9)
Unrealized losses on derivatives designated as cash flow hedges	(4)	(8)
Unrealized losses on debt instruments designated as FVOCI	(29)	(54)
Actuarial gains on defined benefit pension plans	197	194
	\$ 155	\$ 123

NOTE 24 EQUITY ADVANCES

The Corporation does not have share capital. However, the Corporation has received advances from CIC to form its equity capitalization. The advances reflect an equity investment in the Corporation by CIC.

NOTE 25 FINANCIAL INSTRUMENTS

(in millions)

As at March 31			2025		2024	
			Asset (liability)		Asset (liability)	
			Carrying amount	Fair value	Carrying amount	Fair value
Financial assets						
Cash and cash equivalents	FVTPL ¹	1	\$ 50	\$ 50	\$ 374	\$ 374
Accounts receivable and unbilled revenue	AC ²	N/A	491	491	469	469
Debt retirement funds	FVOCI - debt instrument ³	2	931	931	799	799
Financial liabilities						
Accounts payable and accrued liabilities	AC ²	N/A	\$ (715)	\$ (715)	\$ (869)	\$ (869)
Accrued interest	AC ²	N/A	(90)	(90)	(82)	(82)
Dividend payable	AC ²	N/A	-	-	(5)	(5)
Short-term advances	AC ²	N/A	(809)	(809)	(910)	(918)
Long-term debt	AC ²	2	(8,468)	(8,298)	(7,647)	(7,228)

1. FVTPL – measured mandatorily at fair value through profit or loss.

2. AC – amortized cost.

3. FVOCI – fair value through other comprehensive income (loss).

4. Fair values are determined using a fair value hierarchy as follows:

Level 1 – Quoted prices in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted prices included in level 1 that are observable for the asset or liability.

Level 3 – Inputs for the asset or liability that are not based on observable market data.

Not applicable (N/A) – Financial instruments are carried at values which approximate fair value. This includes accounts receivable and unbilled revenue; accounts payable and accrued liabilities; accrued interest; dividend payable; and short-term advances.

Risk management assets and liabilities

(in millions)

As at March 31	Classification	Level ²	2025			2024				
			Asset		(Liability)	Asset		(Liability)		
Natural gas contracts										
Fixed price swap instruments used for hedging ³	FVTPL ¹	2	\$	6	\$	(13)	\$	6	\$	(23)
Fixed price swap instruments	FVTPL ¹	2		1		(1)		-		-
			\$	7	\$	(14)	\$	6	\$	(23)

1. FVTPL – measured mandatorily at fair value through profit or loss.

2. Fair values are determined using a fair value hierarchy as follows:

Level 1 – Quoted prices in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted prices included in level 1 that are observable for the asset or liability.

Level 3 – Inputs for the asset or liability that are not based on observable market data.

3. These natural gas fixed price swap instruments have been designated as cash flow hedges. As such, the effective portion of the changes in fair value related to the derivative financial instruments are recognized in other comprehensive income (loss).

Cash flow hedges

Commodity price risk

The Corporation uses fixed price swap instruments to hedge exposures to anticipated changes in commodity prices on forecasted purchases of natural gas for the production of electricity through certain PPAs that have a cost component based on the market price of natural gas. As at March 31, 2025, the Corporation held the following instruments to hedge exposures to changes in natural gas price risk:

	1 year	2-5 years	More than 5 years
Natural gas hedges			
Total outstanding gigajoules (in millions of GJ)	16	18	-
Net exposure - loss (in millions)	\$ (6)	\$ (1)	\$ -
Weighted average hedged price per GJ	\$ 3.15	\$ 3.11	\$ -
Weighted average forward market price per GJ	\$ 2.80	\$ 3.06	\$ -

NOTE 26 FINANCIAL RISK MANAGEMENT

Market risk

By virtue of its operations, the Corporation is exposed to changes in commodity prices, interest rates and foreign exchange rates. SaskPower may utilize derivative financial instruments to manage these exposures. The Corporation mitigates risk associated with derivative financial instruments through Board-approved policies, limits on use and amount of exposure, internal monitoring and compliance reporting to senior management and the Board.

(a) Commodity prices

Natural gas contracts

The Corporation is exposed to natural gas price risk through natural gas purchased for its natural gas-fired power plants and through certain PPAs that have a cost component based on the market price of natural gas. As at March 31, 2025, the Corporation had entered into natural gas contracts to price manage approximately 48% of its budgeted natural gas exposures for fiscal 2026, 32% for fiscal 2027, 17% for fiscal 2028, and 5% for fiscal 2029.

Based on the Corporation's March 31, 2025, closing positions on its financial natural gas hedges, a one dollar per GJ increase in the price of natural gas would have resulted in a \$33 million improvement in the unrealized market value adjustments recognized in other comprehensive income (loss) for the period. This sensitivity analysis does not represent the underlying exposure to changes in the price of natural gas on the remaining forecasted natural gas purchases which are unhedged as at March 31, 2025.

(b) Interest rates

Short- and long-term borrowings

The Corporation is exposed to interest rate risk arising from fluctuations in interest rates on future short-term and long-term floating and fixed-rate borrowings. Interest rate risk on these borrowings is managed by limiting the amount of ongoing short-term and floating rate borrowings to no more than 15% of its debt equivalent obligations.

As at March 31, 2025, SaskPower had \$809 million in short-term advances. If interest rates were to increase by 100 basis points, this would result in approximately a \$8 million increase in finance charges related to this short-term debt.

Debt retirement funds

Debt retirement funds are monies set aside to retire outstanding debt upon maturity. The Corporation is required to pay annually into debt retirement funds which are held and invested by the Government of Saskatchewan's General Revenue Fund. The Corporation has classified these investments as fair value through other comprehensive income and, therefore, recognized the change in the market value in other comprehensive income (loss) for the period. As at March 31, 2025, SaskPower had \$931 million in debt retirement funds. The fair value of the debt retirement funds is driven largely by interest rates. The estimated impact of a 1% yield curve upward shift, assuming no change in the amount of debt retirement funds, would be a \$81 million decrease in the market value of the debt retirement funds.

(c) Foreign exchange rates

The Corporation faces exposure to the United States/Canadian dollar exchange rate primarily through the sale of electricity to customers in the United States and from the purchase of goods and services that are payable in United States dollars. The Corporation may utilize financial instruments to manage this risk. As at March 31, 2025, the Corporation had no outstanding foreign exchange derivative contracts. The impact of fluctuations in foreign exchange rates on SaskPower's financial instruments is not considered significant to the Corporation. Therefore, a sensitivity analysis of the impact on profit or loss has not been provided.

Credit risk

Credit risk is the risk that one party to a transaction will fail to discharge an obligation and cause the other party to incur a financial loss. Concentrations of credit risk relate to groups of customers or counterparties that have similar economic or industry characteristics that cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

The Corporation does not have a significant concentration of credit risk. The maximum credit risk to which the Corporation is exposed as at March 31, 2025, is limited to the fair value of the financial assets recognized.

(in millions)

As at March 31	2025	2024
Financial assets		
Cash and cash equivalents	\$ 50	\$ 374
Accounts receivable and unbilled revenue	491	469
Risk management assets	7	6
Debt retirement funds	931	799
	\$ 1,479	\$ 1,648

- (a) As at March 31, 2025, SaskPower had \$50 million in cash and cash equivalents. These funds are held at a large Canadian bank with a strong credit rating and, as such, the credit risk associated with cash and cash equivalents is considered low.
- (b) Accounts receivable and unbilled revenue is diversified among many types of customer classes, such as residential, farm and commercial customers throughout Saskatchewan. Other receivables are considered low risk given past collection history. The Corporation uses an allowance matrix to measure the expected credit losses (ECLs) of trade receivables from individual customers, which comprise a very large number of small balances. Loss rates are calculated using a 'roll rate' method based on the probability of a receivable progressing through successive stages of delinquency to write-off.

The following table provides information about the exposure to credit risk and ECLs for trade, unbilled and other receivables from individual customers as at March 31, 2025:

(in millions)

	Gross carrying amount	Weighted-average loss rate	Credit loss allowance
Current	\$ 357	0.3%	\$ 1
30 to 59 days	7	5.0%	-
60 to 89 days	2	10.0%	-
90 to 179 days	4	20.0%	-
180 to 364 days	6	30.0%	3
365 days and greater	18	75.0% - 100.0%	14
	\$ 394		\$ 18
Grant receivables	101	0.0%	-
Miscellaneous and other receivables	14	0.0%	-
	\$ 509		\$ 18

Loss rates are based on actual credit loss past experience and are adjusted to reflect differences between current and historical economic conditions and the Corporation's view of economic conditions over the expected lives of the receivables. The expected credit loss allowance is reviewed quarterly based on an estimate of outstanding amounts that are considered uncollectible.

The movement in the expected credit loss allowance in respect of trade, unbilled and other receivables during the year was as follows:

(in millions)

	Credit loss allowance
Balance, April 1, 2023	\$ 20
Amounts written off	(9)
Net remeasurement of loss allowance	8
Balance, March 31, 2024	\$ 19
Amounts written off	(5)
Net remeasurement of loss allowance	4
Balance, March 31, 2025	\$ 18

- (c) SaskPower is also exposed to credit risk arising from derivative financial instruments if a counterparty fails to meet its obligations. The Corporation maintains Board-approved credit policies and limits in respect to its counterparties.
- (d) Debt retirement funds are on deposit with the Government of Saskatchewan's General Revenue Fund and invested as the Ministry of Finance may determine. As at March 31, 2025, the Ministry has invested these funds primarily in provincial government and federal government bonds with highly graded credit ratings and varying maturities. These maturities coincide with related long-term debt maturities and are managed based on this maturity profile and market conditions. As such, the related credit risk associated with these investments as at March 31, 2025, is considered low.

Liquidity risk

Liquidity risk is the risk that the Corporation is unable to meet its financial commitments as they become due or can do so only at excessive cost. SaskPower manages the Corporation's cash resources based on financial forecasts and anticipated cash flows. The following summarizes the contractual maturities of the Corporation's financial liabilities as at March 31, 2025:

(in millions)

	Carrying amount	Contractual cash flows	Contractual cash flows				
			0-6 months	7-12 months	2 years	3-5 years	More than 5 years
Financial liabilities							
Accounts payable and accrued liabilities	\$ 715	\$ 715	\$ 715	\$ -	\$ -	\$ -	\$ -
Accrued interest	90	90	90	-	-	-	-
Risk management liabilities	14	14	14	-	-	-	-
Short-term advances	809	809	809	-	-	-	-
Long-term debt (principal and interest)	8,468	14,605	282	164	329	1,429	12,401
	\$ 10,096	\$ 16,233	\$ 1,910	\$ 164	\$ 329	\$ 1,429	\$ 12,401

Management believes its ability to generate and acquire funds will be adequate to support these financial liabilities.

NOTE 27 CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure adequate capital to support the operations and growth strategies of the Corporation. SaskPower raises most of its capital through internal operating activities and through funds obtained by borrowing from the Government of Saskatchewan. This type of borrowing allows the Corporation to take advantage of the province's strong credit rating. *The Power Corporation Act* provides SaskPower with the authority to have outstanding borrowings of up to \$10 billion, which includes \$2 billion that may be borrowed by way of temporary loans. Temporary loans include short-term borrowings through the Government of Saskatchewan as well as borrowings made under the \$50 million credit facility provided by a financial institution.

The Corporation's capital structure consists of long-term debt, short-term advances, lease liabilities, retained earnings and equity advances, net of debt retirement funds and cash and cash equivalents.

The Corporation monitors its capital structure using the per cent debt ratio. The per cent debt ratio is calculated as total net debt divided by total capital as follows:

(in millions)

As at March 31	2025	2024
Long-term debt	\$ 8,468	\$ 7,647
Short-term advances	809	910
Lease liabilities	984	850
Total debt	10,261	9,407
Debt retirement funds	931	799
Cash and cash equivalents	50	374
Total net debt	\$ 9,280	\$ 8,234
Retained earnings	2,313	2,237
Equity advances	593	593
Total capital	\$ 12,186	\$ 11,064
Per cent debt ratio	76.2%	74.4%

NOTE 28 COMMITMENTS AND CONTINGENCIES

(in millions)

For the year ended March 31		2026		2027		2028		2029		2030		Thereafter
Power purchase agreements (PPAs) ¹	\$	651	\$	675	\$	726	\$	806	\$	797	\$	12,510
Coal purchase contracts		209		255		245		211		116		-
Natural gas purchase contracts ²		131		80		50		28		5		-
Natural gas transportation and storage contracts		77		58		82		80		65		388
Letters of credit		13		-		-		-		-		-

1. The amounts reflected include all PPAs including those agreements determined to contain a lease, operating agreements and long-term import agreements.

2. Includes fixed price forward contracts of \$290 million which apply for the own-use scope exemption.

The commitments listed above have maturity dates ranging from fiscal 2026 to 2060.

SaskPower has various other legal matters pending which, in the opinion of management, are not likely to have a material effect on SaskPower's consolidated financial position or results of operations.

NOTE 29 NET CHANGE IN NON-CASH WORKING CAPITAL

(in millions)

For the year ended March 31	2025	2024
Accounts receivable and unbilled revenue	\$ (22)	\$ (53)
Inventory	(57)	(42)
Prepaid expenses	(6)	3
Other assets	(8)	(11)
Accounts payable and accrued liabilities	(154)	100
Deferred revenue	16	(27)
	\$ (231)	\$ (30)

NOTE 30 RECONCILIATION OF MOVEMENTS OF ASSETS (LIABILITIES) TO CASH FLOWS ARISING FROM FINANCING ACTIVITIES

(in millions)

	Debt retirement funds	Short-term advances	Long-term debt	Lease liabilities	Total
Balance as at April 1, 2023	\$ 717	\$ (790)	\$ (7,068)	\$ (903)	\$ (8,044)
Changes from financing cash flows:					
Net proceeds from short-term advances	-	(120)	-	-	(120)
Proceeds from long-term debt	-	-	(732)	-	(732)
Repayments of long-term debt	-	-	150	-	150
Debt retirement fund instalments	70	-	-	-	70
Principal repayment of lease liabilities	-	-	-	55	55
Total changes from financing cash flows	70	(120)	(582)	55	(577)
Changes in fair value	(2)	-	-	-	(2)
Other changes:					
Capitalized borrowing costs	-	-	39	-	39
Interest income (expense)	14	(33)	(286)	(132)	(437)
Interest paid	-	30	279	132	441
Non-cash transactions	-	3	(29)	(2)	(28)
Total other changes	12	-	3	(2)	13
Balance as at March 31, 2024	\$ 799	\$ (910)	\$ (7,647)	\$ (850)	\$ (8,608)
Changes from financing cash flows:					
Net repayments of short-term advances	-	101	-	-	101
Proceeds from long-term debt	-	-	(1,021)	-	(1,021)
Repayments of long-term debt	-	-	200	-	200
Debt retirement fund instalments	75	-	-	-	75
Principal repayment of lease liabilities	-	-	-	54	54
Total changes from financing cash flows	75	101	(821)	54	(591)
Changes in fair value	25	-	-	-	25
Other changes:					
Capitalized borrowing costs	-	-	47	-	47
Interest income (expense)	32	(27)	(326)	(131)	(452)
Interest paid	-	31	314	131	476
Non-cash transactions	-	(4)	(35)	(188)	(227)
Total other changes	57	-	-	(188)	(131)
Balance as at March 31, 2025	\$ 931	\$ (809)	\$ (8,468)	\$ (984)	\$ (9,330)

NOTE 31 RELATED PARTY TRANSACTIONS

Included in these consolidated financial statements are transactions with various Saskatchewan Crown corporations, ministries, agencies, boards and commissions related to the Corporation by virtue of common control by the Government of Saskatchewan and non-Crown corporations and enterprises subject to joint control and significant influence by the Government of Saskatchewan (collectively referred to as related parties). Routine operating transactions with related parties are settled at prevailing market prices under normal trade terms.

The Corporation also pays Saskatchewan provincial sales tax on all its taxable purchases to the Government of Saskatchewan Ministry of Finance. Taxes paid are recorded as part of the cost of those purchases.

Key management personnel compensation

Key management personnel include Board Members and executive officers. The compensation paid to key management for employee services is shown below:

(in millions)

For the year ended March 31	2025	2024
Salaries and short-term employee benefits	\$ 5	\$ 4
Post-employment benefits	-	-
Termination benefits	-	-
Other long-term benefits	-	-
	\$ 5	\$ 4

NOTE 32 EMPLOYEE BENEFITS

(in millions)

	Defined benefit pension plan	Other benefit plans	Total
Balance, April 1, 2023	\$ 81	\$ 42	\$ 123
Current service cost	-	4	4
Net interest expense	4	4	8
SaskPower funding contribution	-	-	-
SaskPower benefits paid	-	(8)	(8)
Net actuarial gains	(66)	-	(66)
Balance, March 31, 2024	\$ 19	\$ 42	\$ 61
Current service cost	-	4	4
Net interest expense	1	5	6
SaskPower funding contribution	-	-	-
SaskPower benefits paid	-	(7)	(7)
Net actuarial gains	(3)	-	(3)
Balance, March 31, 2025	\$ 17	\$ 44	\$ 61

Defined benefit pension plan

The Corporation sponsors a defined benefit pension plan (the Plan) that has been substantially closed to employees since 1977. The Plan is governed by *The Superannuation (Supplementary Provisions) Act and Regulations*, as well as *The Power Corporation Superannuation Act*.

The Plan provides benefits based on the average of the highest five years' annual pensionable earnings and years of service. Pensions are increased annually at a rate equal to 70% of the increase in the Saskatchewan Consumer Price Index (CPI). The measurement data at September 30, 2022 was used to measure the obligations and the results were extrapolated to March 31, 2025, to determine the accounting valuation.

The effective date of the most recent actuarial valuation for funding purposes was December 31, 2022. Under current Canada Revenue Agency guidelines, an actuarial valuation for funding purposes is to be completed, at a minimum, every three years.

The Plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the Plan but is obligated to pay benefits under the terms of the Plan as they come due. SaskPower has a Board-approved funding policy which is based on the funding actuarial valuation and requires the Plan deficit to be funded over 10 years when the funded status is less than 95%. In accordance with the funding policy, no contributions were made by SaskPower for the year ended March 31, 2025.

(a) Status of the Plan

The actuarial valuation measured at September 30, 2022, and extrapolated to March 31, 2025, showed that the Plan had an actuarial deficit of \$17 million (2024 – \$19 million). The calculation of the pension plan deficit is as follows:

(in millions)

As at March 31	2025	2024
Plan assets		
Fair value, beginning of period	\$ 627	\$ 609
Actual return on plan assets	50	77
Employer funding contributions	-	-
Employee funding contributions	-	-
Benefits paid	(58)	(59)
Fair value, end of period	\$ 619	\$ 627
Accrued benefit obligation		
Balance, beginning of period	\$ 646	\$ 690
Current service cost	-	-
Interest cost	30	32
Benefits paid	(58)	(59)
Actuarial losses (gains) on accrued benefit obligation	18	(17)
Balance, end of period	\$ 636	\$ 646
Plan deficit	\$ (17)	\$ (19)

(b) Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation are:

As at March 31	2025	2024
Discount rate, beginning of period	4.85%	4.80%
Discount rate, end of period	4.45%	4.85%
Long-term inflation rate	2.00%	2.00%
Assumptions for benefit increases (% of CPI)	70.00%	70.00%
Plan duration (years)	8.70	8.70

The actuarial assumptions are based on management's expectations, independent actuarial advice and guidance provided by IFRS. The discount rate is the yield at the reporting date on high quality bonds that have maturity dates approximating the terms of the Corporation's obligations. The long-term rate of compensation increases assumption is no longer necessary due to the fact that all active members are assumed to retire immediately given their age and service levels. The mortality assumptions are based on the 2014 Canadian Private Sector Mortality Table.

Sensitivity of assumptions

Sensitivity of the defined benefit pension plan to changes in the discount rate, inflation rate, future indexing and life expectancy on the accrued benefit obligation as at March 31, 2025, is as follows:

(in millions)

	Accrued benefit obligation	
	1% increase	1% decrease
Discount rate	\$ (52)	\$ 60
Inflation rate	(25)	27
Future indexing	58	(51)
Life expectancy (each member one year older/younger)	(17)	18

(c) Benefit plan asset allocation

The following is a summary of the asset mix of the Plan's investments:

As at March 31	2025	2024
Equity securities	49.2%	51.9%
Debt securities	24.9%	24.1%
Real estate and infrastructure	25.9%	24.0%
	100.0%	100.0%

(d) Benefit payments

The benefit payments expected to be made to beneficiaries over the next five years are as follows:

(in millions)

For the year ended March 31	2026	2027	2028	2029	2030
Expected benefit payments	\$ 57	\$ 56	\$ 55	\$ 53	\$ 52

Other benefit plans

Other benefit plans include a defined benefit and a defined contribution severance plan, a supplementary superannuation plan and a voluntary early retirement plan.

The significant actuarial assumptions adopted in measuring the Corporation's other benefit plans are:

As at March 31	2025	2024
Discount rate	4.40 - 4.75%	4.65 - 4.75%
Long-term rate of compensation increases	2.00%	2.00%
Long-term inflation rate	2.00%	2.00%
Remaining service life (years)	8.10	7.74
Plan duration (years)	4.30 - 5.10	4.10 - 5.10

Cumulative actuarial losses (gains)

The cumulative amount of actuarial losses (gains) recorded in other comprehensive income (loss) related to the Corporation's defined benefit pension plans is as follows:

(in millions)

As at March 31	2025	2024
Balance, beginning of period	\$ (194)	\$ (128)
Actuarial gains on plan assets:		
Experience adjustments	(21)	(49)
Actuarial losses (gains) on accrued benefit obligations:		
Experience adjustments	-	-
Changes in actuarial assumptions (discount rate)	20	(17)
Changes in actuarial assumptions (future indexing)	(2)	-
Balance, end of period	\$ (197)	\$ (194)

Defined contribution pension plan

The defined contribution pension plan is governed by *The Public Employees Pension Plan Act and Regulations* and certain sections of *The Superannuation (Supplementary Provisions) Act and Regulations*.

Under the defined contribution pension plan, the Corporation's obligations are limited to the contributions for current service. These contributions are charged to income when made. The employee benefit plan expense for the defined contribution pension plan recorded in OM&A expense is as follows:

(in millions)

For the year ended March 31	2025	2024
Employee benefit plan expense	\$ 31	\$ 27

CORPORATE GOVERNANCE

Accountability is a principal component of SaskPower's corporate values and is essential to our relationship with our customers, stakeholders and shareholder. In order to ensure the continued presence of a sound corporate governance structure, our company remains committed to ongoing evaluation. Our aim is to strengthen transparency while executing a comprehensive program of reporting.

COMPANY STRUCTURE

SaskPower is governed by *The Power Corporation Act*. It is subject to the provisions of *The Crown Corporations Act, 1993*, which gives Crown Investments Corporation (CIC) of Saskatchewan, the holding company for Saskatchewan's commercial Crown corporations, broad authority to guide the direction of SaskPower. In practice, directives are normally issued in the following forms: CIC Crown subsidiary policies applying to all CIC Crowns; CIC Board resolutions and directives; and CIC management directives.

As the shareholder of SaskPower, CIC provides oversight of our company's operations. Communication is implemented through written policies and directives issued by CIC's management or its Board of Directors, as well as verbally through discussions with SaskPower leaders. Our company reports to CIC on a regular basis on matters such as Corporate Balanced Scorecard results; financial statements and forecasts; capital expenditures; and debt obligations. SaskPower also provides ad hoc reports to CIC upon request.

Where required by legislation or policy directive, our company submits performance management and investment decisions for review and approval by CIC and provincial cabinet. Through its Chair, who is an outside Director, the SaskPower Board of Directors is accountable to the Minister Responsible for SaskPower. The Minister functions as a link between SaskPower and cabinet, as well as the provincial legislature.

The Legislative Assembly of Saskatchewan appoints members to the Standing Committee on Crown and Central Agencies at the beginning of each legislative session. This committee holds public hearings and is empowered to review the annual reports, financial statements and operations of Crown corporations and related agencies. The Minister Responsible for SaskPower and our company's senior Executives are called before the committee to answer questions about the year under review and issues of topical concern.

GOVERNING OUR COMPANY

The SaskPower Board of Directors is responsible for the general stewardship of our company. It is accountable for setting direction, monitoring and evaluating achievement, as well as identifying any necessary corrective action for SaskPower. The Board works with management to develop and approve SaskPower's Strategic Plan, Annual Budget and Business Plan. It actively identifies business risks and oversees the implementation of appropriate systems to achieve a balance between risks incurred and potential returns.

All of SaskPower's Board Members, including the Chair, are independent of management. The expectations and responsibilities of Directors are outlined in the Terms of Reference. Board Members receive a comprehensive orientation and continuing education. In addition to being subject to SaskPower's Code of Conduct Policy, Board Members are also bound by the CIC Directors' Code of Conduct. Peer evaluations are completed every three years.

Director	Board meetings attended ¹
Chief Darcy Bear ²	4
Bryan Leverick	7
Don Atchison	7
Terry Bergan	8
Amber Biemans	8
Shawn Grice	6
Cherilyn Jolly-Nagel	7
Fred Matheson	7
Robert Nicolay	8
Jeff Richards	6
The Honourable Vaughn Solomon Schofield	3
Thomas Sierzycki ³	3
Rumina Velshi ⁴	6
Stephanie Yong	7

1. There were a total of eight meetings held in 2024-25.
2. Resigned January 24, 2025.
3. Cancelled May 31, 2024.
4. Appointed May 1, 2024.

Information in this section covers the year ended March 31, 2025. Visit [saskpower.com](https://www.saskpower.com) for a full description of SaskPower's corporate governance practices, including Board and Director Terms of Reference, Canadian Securities Administrators (CSA) Governance Guidelines, and SaskPower's Corporate Balanced Scorecard.

During the year, the Board reviewed the strategic direction of SaskPower, as well as numerous operational, financial, environmental, human resource and governance items. The Board also continues to adopt policies and processes to enable effective communication with our shareholder, stakeholders and the public.

As many organizations have increased their reliance on information and operational technology, concerns with cyber security risk have risen over the last number of years. Threats to SaskPower's information and operational technology include malware, targeted attacks and data breaches. SaskPower has undertaken several initiatives to mitigate cyber security risk, including: increasing corporate network and data protection; extending systems monitoring; and improving incident response. SaskPower's Audit & Finance Committee and Board of Directors receive a quarterly update from management on the company's cyber security program.

LEADERSHIP BY COMMITTEE

Our company's Board has four standing committees to assist in designating specific areas of responsibility:

Audit & Finance Committee

Five meetings

Chair: Shawn Grice

Members: Terry Bergan, Cherilyn Jolly-Nagel, Bryan Leverick, Stephanie Yong, and Chief Darcy Bear, ex officio (resigned January 24, 2025)

The Audit & Finance Committee's Terms of Reference mandate the committee to assist the Board in meeting its responsibilities with respect to financial reporting, internal controls and accountability. The committee oversees SaskPower's risk management reporting and directly interacts with the internal and external auditors, as well as the Provincial Auditor of Saskatchewan. The committee ensures that the Board is provided with financial plans, proposals and information that are consistent with our company's overall strategic planning and public policy objectives.

In the 2024-25 fiscal year, the committee reviewed the annual and interim financial statements; risk management reports; the 2025-26 Business Plan; as well as the external auditor and Provincial Auditor 2023-24 audit summaries. The committee also monitored SaskPower's top enterprise risks, ensuring that management has appropriate mitigation plans in place to address them. It also reviewed and approved changes to SaskPower's Enterprise Risk Management Policy to contemplate unique risks relating to SaskPower's nuclear small modular reactor (SMR) project.

The committee monitored SaskPower's capital investments throughout the year, which are required to grow and maintain SaskPower's electricity system and enable the company to continue to provide reliable, affordable electrical power to our customers. This included the selection of Burns & McDonnell to be the company's engineering, procurement and construction partner for the Aspen Power Station project, a 370-MW natural gas-fired power station being constructed near Lanigan. Aspen Power Station will provide reliable, dispatchable generation that will be available when needed to meet demand and also support intermittent, renewable generation such as wind and solar power.

The construction of the Regina Operations and Maintenance Complex at Regina's Global Transportation Hub is another capital project that received ongoing oversight from the committee. Phase one of the project was completed in January 2024. The second and final phase of the project commenced in spring 2024 and will take two years to complete. The facility is part of a long-term strategy to bring 800 frontline employees together in fewer locations. A centralized location will lead to operational efficiencies that will better serve our customers in the region.

Management presented regular updates to the committee on the progress of major corporate initiatives such as SaskPower's migration to SAP S/4HANA, a modern enterprise resource planning suite that will improve overall efficiency. S/4HANA will integrate multiple business functions in a single system, which will enable more streamlined business processes.

Finally, the committee approved the annual work plan for the Internal Audit Department and monitored irregularities. It also held regular *in camera* discussions with SaskPower's Director, Internal Audit.

Safety, Environment & Corporate Responsibility Committee

Four meetings

Chair: Amber Biemans

Members: Don Atchison, Fred Matheson, The Honourable Vaughn Solomon Schofield, Rumina Velshi (appointed June 13, 2024), and Chief Darcy Bear, ex officio (resigned January 24, 2025)

The Safety, Environment & Corporate Responsibility Committee is charged with ensuring that our company proactively addresses safety, health and environmental issues, is in compliance with regulatory and statutory requirements, and strengthens its performance in corporate responsibility. In addition, the committee reviews the findings of the internal and external audits of the company's

environmental and safety management systems, as well as environmental, health and safety facilities. It also monitors the implementation of audit recommendations.

In 2024-25, the committee reviewed the company's safety performance and compliance with environmental legislative, regulatory and corporate standards. This included a review of correspondence from regulators and the results of internal and external audits focused on SaskPower's environmental and safety management systems, as well as regular discussions with SaskPower's Director, Internal Audit, on environmental and regulatory matters.

To ensure effective oversight over regulatory compliance, the committee received quarterly reports on the status of regulatory authorizations for the company's hydroelectric and thermal generating stations. The committee also reviewed, on a quarterly basis, the company's environmental performance and continued to monitor regulatory developments for greenhouse gases and other emissions. In addition, the committee received updates on recent environmental litigation across Canada and considered the potential impacts on the company and its Officers and Directors.

With oversight from the committee, SaskPower is working to enhance transparency and accountability with internal and external audiences concerning corporate responsibility and sustainability issues, activities and goals.

Management continued to provide the committee with regular updates on electrical farm safety, the company's health and safety performance, and its Strategic Plan for Health and Safety. Finally, the committee considered the annual assessment of SaskPower's Dam Safety Program, which evaluates the condition of the company's dam and dyke facilities based on criteria established by the Canadian Dam Association.

Governance & Human Resources Committee

Four meetings

Chair: Robert Nicolay

Members: Don Atchison, Jeff Richards, Stephanie Yong, and Chief Darcy Bear, ex officio (resigned January 24, 2025)

The Governance & Human Resources Committee is responsible for the development, review and effectiveness of SaskPower's corporate governance practices. The committee's governance-related duties include serving as ethics advisor for the Board, monitoring and evaluating overall Board performance every three years, providing guidance on governance issues to Directors, and recommending governance issues for discussion by the full Board. The Governance & Human Resources Committee is also charged with overseeing SaskPower's human resources strategies, programs and practices.

The committee reviewed and approved revisions to SaskPower's Respectful Workplace Policy and Workplace Violence Policy aimed at ensuring that SaskPower is a safe environment for all our employees and that our company is compliant with recent legislative changes. The committee also advised the Board on matters relating to the incorporation of SaskNuclear Incorporated, a wholly-owned subsidiary of SaskPower, such as the adoption of bylaws and constitution of the subsidiary Board of Directors.

The committee received reports on the company's activities in several areas. These included: a report from SaskPower Human Resources on workforce trends and human resources programming and initiatives; a report on the activities of the Saskatchewan Electric Reliability Authority (a committee within SaskPower that is charged with the authority to adopt and enforce electricity reliability standards in Saskatchewan under *The Power Corporation Act*); and an update on succession plan management. The committee also received updates on the company's progress regarding various Indigenous engagement and collaboration initiatives as well as regular reporting from SaskPower's Director, Internal Audit, on matters relating to governance and human resources.

The committee monitored SaskPower's community investment activities, which support community initiatives and educational programs that are aligned with SaskPower's strategic priorities, and reviewed the status of the company's employee benefit plans. Finally, the committee approved a President and Chief Executive Officer (CEO) assessment policy to document the process for evaluating the performance of the President and CEO.

Nuclear Energy Committee

Four meetings

Chair: Bryan Leverick

Members: Terry Bergan, Jeff Richards, Thomas Sierzycki (cancelled May 31, 2024), Rumina Velshi (appointed June 13, 2024), and Chief Darcy Bear, ex officio (resigned January 24, 2025)

The Nuclear Energy Committee's Terms of Reference state that the committee will assist the Board in its responsibility for oversight of matters relating to nuclear safety and nuclear generation technologies, including SMRs.

Management continued to update the committee on progress in the search for a host site for the province's first SMR facility. Two potential sites in the Estevan area have been identified. Detailed assessments of both sites have been ongoing to determine technical suitability for an SMR facility.

The committee increased its awareness of the unique technical aspects of nuclear technology compared to other electrical generation technologies. The committee also reviewed the regulatory framework for the construction and operation of an SMR facility.

The committee received regular updates from management on the planning and engagement work being undertaken for the potential development and construction of SMRs in Saskatchewan. The committee considered management's approach to licensing of SMRs and reviewed the selection criteria being applied to potential sites to inform a site narrowing decision. The siting process has involved ongoing consultation with Indigenous Rights Holders and engagement with the public. SaskPower is in the planning phase for the SMR project and is currently on a path to make a decision whether to proceed with the project in 2029.

BOARD OF DIRECTORS

As at March 31, 2025



Bryan Leverick
Acting Chair
Saskatoon

Bryan Leverick joined the SaskPower Board of Directors in 2008. He currently serves as Acting Chair of the SaskPower Board of Directors and Chair of the Nuclear Energy Committee.

Starting with Alliance Energy Ltd. in 1974, he retired as the company's president in 2022 after nearly 50 years of service. Mr. Leverick has a Business Administration Certificate from the University of Saskatchewan. He holds a Chartered Director designation from McMaster University and is a journeyman electrician with a Gold Seal in project management from the Canadian Construction Association.

In 2003, the Saskatchewan Construction Association awarded Mr. Leverick the Distinguished Service Award.

Board and Volunteer Positions

- Member, Board of Directors, Ducks Unlimited Canada
- Past Chair, Board of Directors, Royal University Hospital Foundation
- Past Chair, Board of Directors, Canadian Electrical Contractors Association
- Past President, Saskatchewan Construction Association
- Past President, Saskatchewan Bid Depository
- Past President, Saskatoon Construction Association
- Past President, Electrical Contractors Association
- Past Chair, Board of Directors, Saskatoon Regional Economic Development Authority
- Past Chair, Board of Directors, Saskatoon City Hospital Foundation



Don Atchison
Member
Saskatoon

Don Atchison joined the SaskPower Board of Directors in 2023.

Mr. Atchison is an independent business consultant. Previously, he was involved in Saskatoon city council for almost a quarter of a century; his 13 years as Mayor make him the longest-serving Mayor in the city's history.

Mr. Atchison was invested with the Saskatchewan Order of Merit in 2019, and named a Paul Harris Fellow by The Rotary Foundation of Rotary International. He was awarded the Medal of Merit by the International Association of Lions Clubs, the Consumer Choice "Man of the Year" Award, and the Canadian Sport Tourism Alliance President's Award for Public Sector Supporter. He was also recognized as an Ambassador by the Saskatoon and Region Home Builders' Association, and recognized by the Saskatoon Police Service.

Board and Volunteer Positions

- Past member, Board of Directors, SGI
- Past Chair, Audit and Finance Committee, Board of Directors, SaskWater



Terry Bergan
Member
Saskatoon

Terry Bergan joined the SaskPower Board of Directors in 2018.

Before his retirement, Mr. Bergan served as President and CEO of International Road Dynamics (IRD). IRD is a world leader in highway traffic management products and systems.

IRD was founded by his father, and Mr. Bergan served for over 30 years at the family-run company in various roles. He built a successful leadership team that contributed to the company's success.

Since 1980, IRD's cumulative sales have exceeded \$1 billion in more than 37 countries. Under Mr. Bergan's leadership, IRD developed over 30 patents.

Mr. Bergan graduated from the Faculty of Engineering at the University of Saskatchewan in 1979.

Board and Volunteer Positions

- Member, Saskatchewan Centre of Excellence for Transportation and Infrastructure
- Member, Transportation Association of Canada
- Member, Canadian Society for Civil Engineering
- Member, Engineering Institute of Canada
- Member, Saskatoon Chamber of Commerce
- Member, North Saskatoon Business Association

- Member, Institute of Corporate Directors
- Member, Saskatoon Regional Economic Development Authority



Amber Biemans, K.C.
Member
Humboldt

Amber Biemans joined the SaskPower Board of Directors in 2022. She currently serves as Chair of the Safety, Environment & Corporate Responsibility Committee.

Raised on an active cattle and grain farm near Bruno, Saskatchewan, Ms. Biemans is a partner at Behiel, Will & Biemans, where she practices in the areas of real estate, estate planning and administration, and corporate law. She received the King's Counsel designation in 2019.

Ms. Biemans attended the University of Saskatchewan, where she obtained a Bachelor of Arts in Psychology and a Bachelor of Laws. She went on to complete her articles at a law firm in Weyburn, Saskatchewan.

In her free time, Ms. Biemans enjoys performing Latin dancing, walking, biking and cross-country skiing.

Board and Volunteer Positions

- Member, Board of Directors, Information Services Corporation
- Past Member, Board of Directors, Carlton Trail Ski Club
- Past member, Board of Directors, SaskWater
- Past member, Board of Directors, Humboldt & District Chamber of Commerce
- Past member, Board of Directors, Humboldt Co-Operative Preschool



Shawn Grice
Member
Regina

Shawn Grice joined the SaskPower Board of Directors in 2022. He currently serves as Chair of the Audit & Finance Committee.

After retiring in 2024 from a long professional career, Mr. Grice currently owns and operates a mixed farming operation in southwest Saskatchewan.

Most recently, Mr. Grice was the President of rSolutions, a privately-held information security and data analytics

firm based in Regina, Saskatchewan, servicing clients across Canada and the United States. In that role, Mr. Grice positioned rSolutions for a strategic investment by a private equity group and through subsequent acquisitions rSolutions will operate under the Arctiq brand.

Mr. Grice started his career in public practice with KPMG Peat Marwick Thorne and then spent several years working for the Government of Saskatchewan in a variety of roles, with over two decades of experience as an executive in the Crown sector.

Mr. Grice has a Bachelor of Commerce Degree (with Great Distinction) from the University of Saskatchewan and is a Chartered Professional Accountant (CPA). He has completed CPA Canada's In-Depth Tax Program and also holds a Chartered Director designation (C.Dir.) from McMaster University and the Conference Board of Canada.

Board and Volunteer Positions

- Past member, Board of Directors, Canadian Bus Association
- Past Board Member, Audit and Finance Committee Chair, Regina Downtown Business Improvement District



Cherilyn Jolly-Nagel
Member
Mossbank

Cherilyn Jolly-Nagel joined the SaskPower Board of Directors in 2017.

Raised on a farm near Mossbank, Saskatchewan, Ms. Jolly-Nagel is a farmer, speaker, director and advocate for global agricultural policy initiatives. She represents the province's agriculture industry around the world and serves as an international director for the Global Farmer Network. In 2021, she was recognized as one of the Top 50 Most Influential People in Canadian Agriculture. In 2025, Ms. Jolly-Nagel was selected as a Nuffield Canada Scholar.

She holds a Hospitality and Tourism Marketing Diploma from Medicine Hat College and an Agriculture Business Diploma from Olds College. Ms. Jolly-Nagel holds an Institute of Corporate Directors Designation (ICD.D). Elected as the first female President of the Western Canadian Wheat Growers Association, Ms. Jolly-Nagel challenged government policies that affected the business of agriculture and is a leader on important issues that impact farmers. Her fresh thinking led her to partner with the team at www.Utensil.ca to launch a unique online training program designed to support those who want to strengthen their business relationships with farmers.

Ms. Jolly-Nagel was Mossbank's first Economic Development Officer. In 2011, she was named one of Saskatchewan's Most Influential Women by SaskBusiness Magazine. She was chosen by the Mattel toy company to take part in an online mentorship program through the launch of a Farmer Barbie.

Along with her family, Ms. Jolly-Nagel owns and operates a grain farm near Mossbank.

Board and Volunteer Positions

- Member, Board of Directors, Mossbank and District Museum
- Coach, Moose Jaw Biathlon Club
- Past President, Board of Directors, Western Canadian Wheat Growers Association
- Past Chair, Board of Directors, Saskatchewan Agri-Value Initiative
- Past member, Board of Directors, Saskatchewan Transportation Company



Fred Matheson
Member
Prince Albert

Fred Matheson joined the SaskPower Board of Directors in 2018. He is the owner of Ted Matheson Men's Wear, a third-generation family business in Prince Albert. Mr. Matheson served as a Prince Albert City Councillor from 2006 to 2009.

Mr. Matheson was a recipient of the Commemorative Medal for the Centennial of Saskatchewan in 2005. He was named Prince Albert Chamber of Commerce Business Leader of the Year in 2013 and won the Saskatchewan ABEX Community Cornerstone Award in 2014. He was recognized as a Lifetime Member of the Prince Albert Chamber of Commerce in 2017 and received the Queen Elizabeth II Platinum Jubilee Medal in 2022.

Mr. Matheson is a graduate of the University of Saskatchewan and holds an Institute of Corporate Directors Designation (ICD.D). He and his wife, Colette, have two children.

Board and Volunteer Positions

- Past President, Kinsmen Club of Prince Albert
- Past Deputy Governor, Kinsmen Club of Saskatchewan
- Past Chair, Board of Directors, Prince Albert Downtown Business Association

- Past Chair, Board of Directors, Prince Albert Police Commission
- Past Chair, Board of Directors, Mont St. Joseph Home



Robert Nicolay, K.C.
Member
Estevan

Robert Nicolay joined the SaskPower Board of Directors in 2018. He currently serves as Chair of the Governance & Human Resources Committee.

He is currently a partner at the law firm Bridges and Company LLP in Estevan, Saskatchewan. From 2007 to 2012, he worked as the Chief of Staff at the Ministry of Corrections, Public Safety and Policing.

Mr. Nicolay is a graduate of the University of Saskatchewan, College of Law. He is also a graduate of the Directors Education Program at the Rotman School of Management and holds an Institute of Corporate Directors Designation (ICD.D).

Board and Volunteer Positions

- Member, Rotary Club of Estevan
- Past member and Administrative Director, Saskatchewan Young Professionals and Entrepreneurs
- Past member, Saskatoon Club



Jeff Richards
Member
Weyburn

Jeff Richards joined the SaskPower Board of Directors in 2021. Born and raised in southeast Saskatchewan, Mr. Richards has a diverse background in business, government and leadership. After more than a decade as a small business owner, he has spent the last 15 years in senior leadership roles across a number of sectors.

Currently, he is the Mayor of Weyburn, as well as the Executive Director of the Weyburn Wor-Kin Shop.

Mr. Richards holds the Institute of Corporate Directors Designation (ICD.D), as well as the Credit Union Director Achievement (CUDA) certification.

As a dedicated community builder, Mr. Richards devotes his time to organizations that are working to build stronger and better communities. He has worked with business groups in Canada and the United States.

Board and Volunteer Positions

- Board Chair, Weyburn Credit Union
- Director, Weyburn Board of Police Commissioners
- Past Councillor, City of Weyburn
- Past Director, SaskWater
- Past Chair, Governance & Corporate Responsibility Committee, SaskWater
- Past Chair, Weyburn District Regional Planning Commission
- Past President, Weyburn & District United Way
- Past Director, Estevan Chamber of Commerce
- Past Director, Weyburn Chamber of Commerce



The Honourable Vaughn Solomon Schofield
Member
Regina Beach

The Honourable Vaughn Solomon Schofield joined the SaskPower Board of Directors in 2021. She has had a successful career in business and has provided leadership to international, national and provincial organizations.

Mrs. Solomon Schofield was born and raised in Regina and was educated at the University of Saskatchewan (Regina Campus) and the Rae-Vogue School in Chicago. She served as Saskatchewan's 21st Lieutenant Governor from 2012 to 2018, as well as the Chancellor of the Saskatchewan Order of Merit. Prior to her appointment as Lieutenant Governor, she was President and CEO of Western Group of Companies, a business real estate organization holding interests throughout Western Canada. Mrs. Solomon Schofield received the Saskatchewan Volunteer Medal in 2009, the Commemorative Medal for the Centennial of Saskatchewan in 2005, and the Queen Elizabeth II Diamond Jubilee Medal in 2012. She is a strong supporter of the Canadian Forces and was awarded the prestigious Canadian Forces Medallion for Distinguished Service in 2009.

In the 1980s, Mrs. Solomon Schofield was Chair of the Board for Crime Watch, a 200,000-member crime prevention organization. She travelled throughout North and South America to establish Crime Watch groups. Fluent in English and Spanish, Mrs. Solomon Schofield worked with the government of Guayaquil, Ecuador, to establish their Crime Watch group and acted as an interpreter. She also hosted a Crime Prevention television talk show for four years in Fort Lauderdale, Florida, and was twice voted Florida's Crime

Prevention Woman of the Year. She has served on numerous municipal, provincial and federal boards.

She and her late husband Gordon Schofield have two children and four grandchildren.

Board and Volunteer Positions

- Chair, Saskatchewan Police Commission
- Provincial Chair, Canadian Forces Liaison Council
- Honorary Colonel, 10 Field Artillery Regiment



Rumina Velshi
Member
Toronto

Rumina Velshi joined the SaskPower Board of Directors in 2024.

With over four decades of experience in the nuclear energy industry, Ms. Velshi is a senior leader and strategic advisor to investors, project proponents, and technology developers worldwide, as well as governments, international organizations, and regulatory agencies.

Ms. Velshi is sought after by organizations around the world for her strategic and operating advice on matters ranging from safety, compliance, and regulatory issues, to investment due diligence, strategic transactions, and innovative nuclear projects, including small modular reactor projects.

Over the course of her career, Ms. Velshi worked in various capacities as a senior executive at Ontario Hydro and Ontario Power Generation. She most recently served as President and CEO of the Canadian Nuclear Safety Commission, a role she held for five years after previously serving as a Commission member for seven years. Ms. Velshi is a strategic advisor at Torys LLP and also a cofounder and principal of a startup nuclear energy company in Japan.

In November 2023, Ms. Velshi was presented the "Icon of Nuclear" award by the International Framework for Nuclear Energy Cooperation in recognition for her global leadership as a nuclear regulator. She was appointed a nonresident senior fellow at the Atlantic Council's Nuclear Energy Policy initiative in May 2024.

Ms. Velshi holds a Bachelor of Applied Science Degree in civil engineering, and master's degrees in both chemical engineering and business administration from the University of Toronto. In 2023 she completed the ICD-Rotman Directors of Education Program.

Board and Volunteer Positions

- Member, International Nuclear Safety Advisory Group to the Director General of the International Atomic Energy Agency
- Member, Hydro Ottawa Board of Directors
- Chair, OECD Nuclear Energy Agency High Level Group on Stakeholder Engagement and Trust
- International Expert Advisor to Japan's Nuclear Regulation Authority



Stephanie Yong
Member
Saskatoon

Stephanie Yong joined the SaskPower Board of Directors in 2022.

Ms. Yong is a strategic solutions specialist and award-winning entrepreneur with deep expertise in design thinking, strategic planning, and impactful communication. As Co-Founder of Sohkiwin Solutions, she works at the intersection of Indigenous community collaboration and corporate innovation to drive generational change. She also has a consultancy practice, Stephanie Yong Consulting, where she helps organizations unlock human-centered solutions to complex problems.

With a strong background in leadership, education, and economic development, Ms. Yong has held roles at the Saskatoon Regional Economic Development Authority and served as a lecturer at the Edwards School of Business for over a decade. Her work spans entrepreneurship, governance, and community impact.

A recipient of the Queen Elizabeth II Platinum Jubilee Medal and CBC's Future 40 Award, Ms. Yong is known for her ability to build partnerships, lead with insight, and transform strategy into action.

Board and Volunteer Positions

- Vice Chair and Audit and Finance Committee Chair, Board of Directors, Saskatchewan Opportunities Corporation
- Chair and Governance Committee Chair, Board of Directors, Saskatoon Public Schools Foundation
- Member, Board of Directors, Creative Saskatchewan

COMPENSATION

Under the authority of *The Crown Corporations Act, 1993*, SaskPower's shareholder, CIC, directs the compensation received by Directors. In addition to reimbursement for reasonable expenses incurred while performing their duties (including related travel, meal and accommodation costs), Directors receive an annual retainer and meeting fees for service:

- The Board Chair receives an annual retainer of \$40,000.
- Board Members receive an annual retainer of \$25,000.
- The Audit & Finance Committee Chair receives an annual retainer of \$3,500.
- Other Committee Chairs receive an annual retainer of \$2,500.
- Committee Members receive a daily meeting fee of \$750 for a full day and \$375 for a half day (less than four hours).

EXECUTIVE TEAM

As at March 31, 2025



Rupen Pandya
President and
Chief Executive Officer

Rupen Pandya was named the President and Chief Executive Officer of SaskPower in 2022. He is also the President and Chief Executive Officer of SaskNuclear, the wholly owned subsidiary of SaskPower that was created in 2024 to advance the province's small modular reactor development project.

Before joining SaskPower, Rupen was the Deputy Minister of Finance and Secretary to the Treasury Board for the Government of Saskatchewan.

He has more than 25 years of public service experience in Saskatchewan, including previous positions as the President and Chief Executive Officer of SaskBuilds, and Assistant Deputy Minister roles with the Ministry of the Economy and the Ministry of Advanced Education, Employment and Immigration.

He holds Bachelor and Master of Arts degrees from the University of Regina.

Board and Volunteer Positions

- Member, Board of Directors, Conference Board of Canada
- Member, Board of Directors, Canadian Nuclear Association
- Member, Board of Directors, Electricity Canada
- Member, Small Modular Reactor Leadership Table, Natural Resources Canada
- Member, Board of Directors, Western Energy Institute
- Member, Board of Directors, South Saskatchewan Community Foundation
- Member, Leaders Council, University of Regina
- Past member, Board of Directors, Credit Union Deposit Guarantee Corporation
- Past member, Board of Directors, Saskatchewan Apprenticeship and Trade Certification Commission
- Past member, Board of Directors, Physician Recruitment Agency of Saskatchewan
- Past member, Board of Directors, Canadian Council for Public-Private Partnerships
- Past trustee, Public Employees Pension Plan

- Past trustee, Municipal Employees Pension Plan
- Past trustee, Saskatchewan Student Aid Fund



Rhea Brown
Executive Vice-President, Customer Experience
and Procurement

Rhea Brown was named Executive Vice-President, Customer Experience and Procurement in 2023.

Rhea has been with SaskPower since 2008, starting in Customer Service as a Key Account Manager, then transitioning to the Director of Key Accounts and Customer Relations in 2012 before taking on the Director of Procurement and Contracts Management role in 2019.

Before joining SaskPower, Rhea held a number of leadership positions in the private sector, most notably a decade-long career working for a sales and marketing company in customer development and supply chain roles in Vancouver and Toronto.

She holds a Bachelor of Commerce from the University of Saskatchewan and holds an Executive Master of Business Administration from the Kenneth Levene Graduate School of Business at the University of Regina.

Board and Volunteer Positions

- Member, Board of Directors, Regina Immigrant Women's Centre
- Member, Board of Directors, Power Corporation Superannuation Plan



Len Clewett
Executive Vice-President,
Nuclear Development

Leonard (Len) Clewett became the Executive Vice-President, Nuclear Development in 2024.

Len brings more than 30 years of experience in the nuclear industry to the role. Before joining SaskPower, he held a number of senior leadership roles in North America's nuclear power generation industry, including with XCEL Energy, EXELON, Florida Power Corporation and United Engineers & Constructors. Most recently he was the Executive Vice-President and Chief Nuclear Officer at Bruce Power in Ontario, one of the world's largest nuclear generating facilities.

He has a Bachelor of Science in Mechanical Engineering from Lehigh University and a Master in Business Administration from Southern New Hampshire University. He also held a State of New Hampshire Professional Engineers license and a Senior Reactor Operator license from the United States Nuclear Regulatory Commission.

Board and Volunteer Positions

- Past Chair, World Association of Nuclear Operators International Participants, Forum
- Past Co-Chair, Canadian Regulator/CNO Working Group
- Past Chair, Canadian Chief Nuclear Officer Forum
- Past member, Executive Advisory Committee, North American Young Generation in Nuclear



Darren Foster

Associate Vice-President,
Corporate Strategy & Planning

Darren Foster was appointed Associate Vice-President of Corporate Strategy & Planning in 2025. He provides executive oversight for integrated strategy and corporate development, as well as advancing enterprise performance and strategic execution. This includes guiding the business in developing solutions and collaborative partnerships that will deliver on key strategic initiatives.

Darren brings extensive experience in strategy development and execution, regulatory affairs, corporate performance, sustainability, communications, and shareholder relations. In addition to over 20 years of experience in the electricity industry, his career has included a decade leading his own consultancy, as well as time as a Creative Director at a national advertising agency, administrator at a university college, and journalist at a developing world news agency based in London, UK.

Darren holds a Bachelor of Arts in Journalism and Communications from the University of Regina and has studied extensively at the Banff Centre for Arts and Creativity.

Board and Volunteer Positions

- Member, Board of Directors, International Carbon Capture and Storage Knowledge Centre



Kory Hayko

Executive Vice-President,
Chief Operating Officer

Kory Hayko was named Executive Vice-President and Chief Operating Officer in 2023. He became Vice-President, Transmission and Industrial Services in 2017, and previously served as Vice-President, Commercial and Industrial Operations, Fuel and Cross-Crown Collaboration, and acting Vice-President, Customer Services. He has also been President and Chief Executive Officer of NorthPoint Energy Solutions, a SaskPower subsidiary, since July 2014.

In his more than 30 years at SaskPower, Kory has served in numerous roles, including Director of Energy Management and Trading, and Director of Gas Management.

He holds a Bachelor of Applied Science in Industrial Systems Engineering and a Master of Applied Science in Energy Systems, both from the University of Regina.

Kory is a member of the Association of Professional Engineers and Geoscientists of Saskatchewan.

Board and Volunteer Positions

- Member, Industry Advisory Board, University of Regina Faculty of Engineering
- Past member, Board of Directors, International Carbon Capture and Storage Knowledge Centre



Troy King

Executive Vice-President, Chief Strategy,
Technology and Financial Officer

Troy King was named Executive Vice-President and Chief Strategy, Technology and Financial Officer in 2023. He previously held the position of Vice-President, Finance and Business Performance and Chief Financial Officer starting in 2017. Troy has worked at SaskPower since 1996 in many leadership roles including Director of Corporate Planning and Controller.

He holds a Business Administration degree from the University of Regina and is a Chartered Professional Accountant (CPA, CMA).

Board and Volunteer Positions

- Chair, Board of Directors, Power Corporation Superannuation Plan
- Audit Committee Chair, Board of Directors, Hospitals of Regina Foundation

- Member, Board of Directors, Public Employees Pension Plan
- Co-Chair, Electricity Canada CFO Committee



Howard Matthews

Vice-President, Generation

Howard Matthews was named Vice-President, Generation, in 2023. He was appointed Vice-President, Power Production, in 2015, after serving as acting Vice-President in 2014.

Howard also served as President and Chief Executive Officer of SaskPower International, a SaskPower subsidiary, from 2015 until its dissolution in 2021.

Over his career, he has held many roles at SaskPower, starting as an electrical engineer in 1989. He also served as Director at the Poplar River Power Station in Coronach.

Before SaskPower, Howard was a computer programmer and worked for the Saskatchewan Research Council, Northern Telecom and the Saskatchewan Mining and Development Corporation. He has also worked as a field engineer for Husky Injection in Toronto.

He holds Bachelor of Commerce and Bachelor of Electrical Engineering degrees, both from the University of Saskatchewan.

He is a member of the Association of Professional Engineers and Geoscientists of Saskatchewan.

Board and Volunteer Positions

- Past member, Board of Directors, International Carbon Capture and Storage Knowledge Centre



Gregg Milbrandt

Vice-President,
Asset Strategy and Planning

Gregg Milbrandt was named Vice-President, Asset Strategy and Planning in 2024. He has over 25 years of operations, engineering, asset management, construction, and commissioning experience with the company.

Gregg initially joined SaskPower in 1999 as a construction engineer. He went on to serve in a number of leadership roles with the company, including as the Director, Shand Power Station for five years and more recently as the Director, Boundary Dam Power Station and Carbon Capture Facility beginning in 2020.

He holds a Bachelor of Science in Mechanical Engineering degree from the University of Saskatchewan, and is a member of the Association of Professional Engineers and Geoscientists of Saskatchewan.

Board and Volunteer Positions

- Member, Saskatchewan Electric Reliability Authority



Rachelle Verret Morphy, K.C.

Executive Vice-President, Legal &
Corporate Services and General Counsel

Rachelle Verret Morphy was named Executive Vice-President, Legal and Corporate Services and General Counsel, and served as Acting Executive Vice-President, People, Safety and Indigenous and Corporate Relations, in 2023. She became Vice-President, Corporate and Regulatory Affairs and General Counsel in 2017, and in 2021 also took on the role of Acting Vice-President, Human Resources and Safety.

Rachelle joined the company as Assistant General Counsel in the Law Department in 2005, and became the Vice-President of Law, Land and Regulatory Affairs, in 2011.

Before joining SaskPower, Rachelle worked for a federally-regulated financial institution, a law firm and a professional accounting firm.

She has a Bachelor of Laws from the University of Saskatchewan and a Bachelor of Commerce (Honours) from the University of Ottawa. As well, Rachelle holds an Institute of Corporate Directors Designation (ICD.D) and a Chartered Professional Accountant (CPA) designation.

Board and Volunteer Positions

- Vice-Chair, Board of Directors, Power Corporation Superannuation Plan
- Chair, Saskatchewan Electric Reliability Authority



Ryan Neufeld

Vice-President,
Engineering and Construction

Ryan Neufeld was named Vice-President, Engineering and Construction in 2023. He has 27 years of experience in numerous areas within SaskPower, including Transmission, Distribution, and Key Accounts.

Over his career he has held many roles at SaskPower, starting as an electrical engineering technologist in 1998 performing commissioning and testing within Transmission, Distribution,

and Generation. He also served as Director, Distribution Construction & Work Management and Director, Distribution Operations North.

Before SaskPower, Ryan worked at ATCO Electric as a Station Technologist in northern Alberta.

He holds a diploma in Electrical Engineering Technology from Palliser Institute, a Journeyman Power System Electrician certificate from Alberta, and a certificate in Business Administration from the University of Saskatchewan.

Board and Volunteer Positions

- Member, Board of Directors, International Carbon Capture and Storage Knowledge Centre
- Member, Transmission Council, Electricity Canada
- Member, Executive Operations Board Committee, Western Energy Institute
- Member, Board of Directors, Saskatchewan Common Ground Alliance



Kathryn Pollack

Executive Vice-President,
People, Safety & Indigenous
and Corporate Relations

Kathryn Pollack was named Executive Vice-President, People, Safety and Indigenous and Corporate Relations in 2023.

Prior to joining SaskPower, Kathryn held a number of leadership positions in government and private industry in Saskatchewan, including Chairperson and CEO of the Public Service Commission, Chief Procurement Officer for the Ministry of SaskBuilds and Procurement, Chief Strategy Officer with Praxis Consulting and Land, Environment & Community Manager with Vale.

She studied Fine Arts at Collège du Vieux Montréal and holds a Master of Business Administration from the University of Regina and a Petroleum Land Administration Certificate from the Southern Alberta Institute of Technology in Calgary. She has also completed the Directors Education Program through the Rotman School of Business and Institute of Corporate Directors (ICF) and is a Certified Leadership Coach.

In 2022, she received the Queen Elizabeth II Platinum Jubilee Medal (Saskatchewan) for Public Service.

Board and Volunteer Positions

- Director, Vice-Chair, Conexus Credit Union Board of Directors
- Member, Levene Leaders Council and Paul J. Hill Advisory Board, University of Regina



Shawn Schmidt

Vice-President,
Transmission and Distribution

Shawn Schmidt was named Vice-President, Transmission & Distribution in 2023. He had served as Vice-President, Distribution and Customer Services since 2018.

Shawn has spent 35 years in the utility, mining and consulting industries. He joined SaskPower in 2001 in Customer Services Key Accounts. He then became Engineering Supervisor, followed by Regional Manager in Distribution Operations. Shawn also served as Director, Transmission Operations and Maintenance for eight years.

He has a Bachelor of Science in Electrical Engineering from the University of Saskatchewan. In 2018, he co-authored a paper for the Institute of Electrical and Electronics Engineers: *Flashover Performance of Live-Line Tools in High Voltage Environments*. He is a member of the Association of Professional Engineers and Geoscientists of Saskatchewan.

Board and Volunteer Positions

- Chair, Distribution Council, Electricity Canada
- Member, Board Committee on Net Zero, Electricity Canada
- Member, Saskatchewan Electric Reliability Authority

COMPENSATION

CIC has established a framework for Executive compensation, and SaskPower's Board can approve compensation packages within that framework. The Board has delegated responsibility for addressing and making recommendations concerning Executive compensation issues to the Governance & Human Resources Committee. Executive performance is assessed annually against corporate and individual objectives that are aligned with our company's Strategic Plan. The mandate for Executive compensation for Saskatchewan Crown corporations is established and monitored by CIC.

Direct reports of SaskPower's President and CEO, including all Executive Members, are required by legislation to file and report the details of their compensation and benefits and any changes to the Clerk of the Saskatchewan Legislature within 14 days of occurrence. In addition, the Crown and Central Agencies Committee of the Legislative Assembly of Saskatchewan requires Crown corporations, including SaskPower, to file an annual payee list that includes the total compensation of Executive Members.

FIVE-YEAR FINANCIAL SUMMARY

(in millions)	2024-25	2023-24	2022-23	2021-22	2020-21
Consolidated Statement of Income (Loss)					
Revenue					
Saskatchewan electricity sales	\$ 3,110	\$ 3,096	\$ 2,844	\$ 2,713	\$ 2,615
Exports	28	129	139	77	53
Other revenue	116	154	84	95	103
	3,254	3,379	3,067	2,885	2,771
Expense					
Fuel and purchased power	1,105	1,240	1,283	1,033	807
Operating, maintenance and administration	865	811	792	711	700
Depreciation and amortization	638	605	597	612	595
Finance charges	418	409	406	401	426
Taxes	100	92	86	81	79
Other expenses	52	38	75	36	4
	3,178	3,195	3,239	2,874	2,611
Net income (loss)	\$ 76	\$ 184	\$ (172)	\$ 11	\$ 160
Consolidated Statement of Financial Position					
Assets					
Current assets	\$ 1,010	\$ 1,249	\$ 989	\$ 754	\$ 811
Property, plant and equipment	12,294	11,173	10,621	10,133	9,816
Right-of-use assets	551	414	463	516	565
Intangible assets	69	82	72	77	68
Debt retirement funds	931	799	717	738	865
Other assets	35	27	16	11	8
Total assets	\$ 14,890	\$ 13,744	\$ 12,878	\$ 12,229	\$ 12,133
Liabilities and equity					
Current liabilities	\$ 1,903	\$ 2,161	\$ 1,905	\$ 1,690	\$ 1,301
Long-term debt	8,268	7,447	6,918	6,239	6,501
Lease liabilities	942	795	849	904	946
Employee benefits	61	61	123	131	208
Provisions	655	327	341	305	324
Equity	3,061	2,953	2,742	2,960	2,853
Total liabilities and equity	\$ 14,890	\$ 13,744	\$ 12,878	\$ 12,229	\$ 12,133
Consolidated Statement of Cash Flows					
Cash provided by operating activities	\$ 481	\$ 751	\$ 445	\$ 738	\$ 814
Cash used in investing activities	(1,391)	(1,133)	(1,017)	(912)	(658)
Cash provided by (used in) financing activities	586	564	732	108	(294)
(Decrease) increase in cash position	\$ (324)	\$ 182	\$ 160	\$ (66)	\$ (138)
Financial Indicators					
Dividends	\$ -	\$ 18	\$ -	\$ 3	\$ 48
Capital expenditures	\$ 1,497	\$ 1,213	\$ 1,065	\$ 922	\$ 693
Return on equity	2.6%	6.7%	(6.3%)	0.4%	5.8%
Per cent debt ratio	76.2%	74.4%	74.7%	71.9%	71.4%

FIVE-YEAR REVENUE STATISTICS

	2024-25	2023-24	2022-23	2021-22	2020-21
Number of Saskatchewan customer accounts					
Residential	419,908	415,037	411,629	407,995	403,782
Farm	57,724	57,649	57,760	57,949	58,035
Commercial	65,475	65,303	65,051	64,764	64,272
Oilfield	18,993	19,318	19,281	19,103	18,960
Power	130	134	126	127	128
Reseller	2	2	2	2	2
Total number of Saskatchewan customer accounts	562,232	557,443	553,849	549,940	545,179
Electricity sales (in millions)					
Residential	\$ 637	\$ 632	\$ 606	\$ 595	\$ 579
Farm	188	198	185	178	188
Commercial	557	557	528	504	487
Oilfield	477	469	440	416	390
Power	879	895	815	777	748
Reseller	104	105	99	98	94
	2,842	2,856	2,673	2,568	2,486
Federal carbon charge collected	268	240	171	145	129
Saskatchewan electricity sales	3,110	3,096	2,844	2,713	2,615
Exports	28	129	139	77	54
Total electricity sales	\$ 3,138	\$ 3,225	\$ 2,983	\$ 2,790	\$ 2,669
Electricity sales (GWh)					
Residential	3,248	3,224	3,294	3,331	3,224
Farm	1,226	1,305	1,288	1,285	1,348
Commercial	3,744	3,749	3,776	3,690	3,540
Oilfield	4,395	4,320	4,211	4,013	3,727
Power	10,228	10,531	10,087	9,821	9,409
Reseller	1,143	1,150	1,162	1,160	1,129
Saskatchewan electricity sales	23,984	24,279	23,818	23,300	22,377
Exports	438	763	932	695	526
Total electricity sales	24,422	25,042	24,750	23,995	22,903
Average electricity sales price (\$/MWh)					
Residential	\$ 196	\$ 196	\$ 184	\$ 179	\$ 180
Farm	153	152	144	139	139
Commercial	149	149	140	137	138
Oilfield	109	109	104	104	105
Power	86	85	81	79	79
Reseller	91	91	85	84	83
Exports	64	169	149	111	103
Total weighted average electricity sales price	\$ 118	\$ 119	\$ 114	\$ 110	\$ 111
Average annual usage per residential customer (kWh)	7,735	7,768	8,002	8,164	7,985
System-wide average rate increases	0.0%	4.0%	4.0%	0.0%	0.0%
		(Apr 1)	(Sep 1)		
Federal carbon charge rate rider increases	2.9%	0.5%	3.0%	0.0%	0.6%
	(Jan 1)	(Jan 1)	(Jan 1)		(Jan 1)

FIVE-YEAR GENERATING AND OPERATING STATISTICS

	2024-25	2023-24	2022-23	2021-22	2020-21
Net electricity supplied (GWh)					
Gas	12,426	11,934	10,575	10,766	10,551
Coal	6,245	7,895	8,424	9,479	8,146
Hydro	2,769	2,490	3,244	2,850	4,277
Wind	2,531	1,981	2,177	1,661	913
Imports	1,929	2,027	1,806	752	629
Solar	94	71	55	14	1
Other ¹	180	177	145	124	117
Gross electricity supplied	26,174	26,575	26,426	25,646	24,634
Line losses	(1,752)	(1,533)	(1,676)	(1,651)	(1,731)
Net electricity supplied	24,422	25,042	24,750	23,995	22,903
Electricity supplied (GWh)					
SaskPower owned	17,891	18,480	18,618	19,634	19,511
Independent power producer and imports	8,283	8,095	7,808	6,012	5,123
Gross electricity supplied	26,174	26,575	26,426	25,646	24,634
Available generating capacity (net MW)					
Gas	2,434	2,065	2,160	2,160	2,160
Coal	1,389	1,389	1,389	1,389	1,530
Hydro ²	1,153	1,155	1,154	989	989
Wind	818	617	617	626	241
Solar	103	95	83	54	39
Other	33	34	34	28	28
Total available generating capacity	5,930	5,355	5,437	5,246	4,987
Available generating capacity (net MW)					
Fossil fuel generating capacity	3,823	3,454	3,549	3,549	3,690
Renewable generating capacity	2,107	1,901	1,888	1,697	1,297
Total available generating capacity	5,930	5,355	5,437	5,246	4,987
Peak loads (net MW)					
Annual peak load	3,838	3,896	3,800	3,910	3,722
Minimum load	2,135	2,111	2,032	2,106	1,918
Summer peak load	3,669	3,669	3,597	3,547	3,481
Lines in service (circuit km)					
Transmission lines	14,816	14,930	14,915	14,673	14,600
Distribution lines	144,868	144,768	145,792	142,713	142,972
Total lines in service	159,684	159,698	160,707	157,386	157,572
Number of permanent full-time employees	3,276	3,212	3,096	3,057	3,036

1. Includes small independent power producers (IPP), with generation sourced from flare gas, waste heat recovery, landfill gas and biomass. The 2020-21 amount reported includes generation sourced from customer-generated solar facilities.

2. Includes import power purchase agreements with Manitoba Hydro.

GREENHOUSE GAS (GHG) EMISSIONS

	GHG emissions ¹ (million tonnes of carbon dioxide equivalent (CO ₂ e))	Carbon intensity: supply ² (tonnes of CO ₂ e/GWh)	Carbon intensity: consumption ² (tonnes of CO ₂ e/GWh)
2005	14.2	712	778
2020	12.8	518	570
2021	14.9	583	637
2022	13.8	525	561
2023	13.6	511	543
2024	12.8	488	523

1. Includes GHG emissions from SaskPower-owned facilities and large independent power producers. GHG emissions and intensity will be subject to fluctuation depending on load growth and the fuel mix required to ensure reliability.
2. Supply intensity provides the amount of CO₂e emissions produced per gigawatt hour (GWh) of electricity supplied to the system. Consumption intensity considers line losses and Renewable Energy Certificate (REC) sales in the calculation and therefore represents an appropriate intensity number for the end consumer.

GLOSSARY

Baseload

The minimum amount of electricity needed to be supplied to the grid at all times to meet steady and often essential levels of demand. Electricity utilities seek to have access to constantly operating and highly reliable generation sources to meet their baseload needs. Coal and hydro generation are excellent sources of baseload power generation.

Battery energy storage system (BESS)

Acts as a support to intermittent generation options, like solar and wind. A BESS will help to balance the power system when demand spikes for short periods of time.

Biomass

Energy resources derived from organic matter. These include wood, agricultural waste and other living-cell material that can be burned to produce heat energy.

Capacity

The greatest load that can be supplied by a generating unit, power station or an entire provincial grid system.

Carbon capture and storage (CCS)

Technology that reduces greenhouse gas emissions by capturing carbon dioxide, typically at fossil-fueled power plants, and storing it in geological reservoirs deep underground.

Carbon dioxide (CO₂)

Carbon dioxide is produced in fossil fuel-based electricity generation.

CO₂ equivalent (CO₂e)

Unit of measure for greenhouse gases that includes CO₂ emissions as well as the CO₂ equivalents (CO₂e) for methane (CH₄) and nitrous oxide (N₂O) emissions.

Cogeneration

The simultaneous generation of electricity and useful heat or steam. The heat could be put in use in an industrial process or to heat a facility or community. The electricity could be used by the owner or sold.

Demand

The rate at which electric energy is delivered at a given instant or averaged over a period of time. It is measured in kilowatts, megawatts, etc.

Dispatchable

Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other consideration. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.

Distribution

Process of moving electric energy at lower voltages from major substations to customers.

Fly ash

The fine powder by-product resulting from the combustion of pulverized coal used in SaskPower's coal-fired generating stations.

Gigawatt (GW)

A unit of bulk power; one billion watts or one million kilowatts.

Gigawatt hour (GWh)

A unit of bulk energy; one million kilowatt hours.

Independent power producer (IPP)

An unregulated entity that owns power plants and generates electricity in the competitive wholesale market.

International Financial Reporting Standards (IFRS)

Guidelines and rules set by the International Accounting Standards Board that companies follow when compiling financial statements. IFRS replaced the previous Canadian Generally Accepted Accounting Principles as the acceptable set of accounting standards for publicly accountable enterprises in Canada.

Kilowatt hour (kWh)

A unit of bulk energy; 1,000 watt hours. The measurement is generally used for billing residential customers.

Load

The amount of electric power or energy consumed by a particular customer or group of customers.

Megawatt (MW)

A unit of bulk power; 1,000 kilowatts. The unit generally used to describe the output of a commercial generator.

Megawatt hour (MWh)

A unit of bulk energy; 1,000 kilowatt hours.

Net metering

The offsetting of electricity consumption by a customer against the same customer's production of electricity, typically from a small-scale renewable energy source such as wind or solar.

Nuclear small modular reactors (SMRs)

Nuclear fission reactors that are smaller than conventional nuclear reactors. In areas lacking sufficient lines of transmission and grid capacity, SMRs can be installed into an existing grid or remotely off-grid, providing low-carbon power for industry and consumers.

Open Access Transmission Tariff (OATT)

The SaskPower OATT allows eligible users to access our transmission system to transport electricity to wholesale customers within Saskatchewan or across the province to other jurisdictions. The OATT also ensures SaskPower can access the transmission systems of other utilities.

Peak load demand or peak energy demand

The maximum amount of electric power or energy consumed by a particular customer or group of customers at a precise time.

Power purchase agreement (PPA)

A contract between electricity producers in which one party sells energy and/or generating capacity to another, who generally serves end-use retail customers. For example, instead of building a new power plant, an electric company can choose to enter into a PPA.

Renewable generation

Electricity generated from sources that can be used continuously without being depleted and are generally free of greenhouse gas emissions.

Smart meter

An electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing.

Switching station

A facility containing transformers, regulators, switches and protective equipment for changing transmission voltages between transmission lines.

Transmission

Process of moving electric power in bulk at higher voltages from the source of supply to distribution centres.

SASKPOWER SYSTEM MAP

TOTAL AVAILABLE GENERATING CAPACITY AS AT MARCH 31, 2025: 5,930 MEGAWATTS (MW)

HYDRO TOTAL CAPACITY - 863 MW

- H1** Athabasca Hydroelectric System - 19 MW
- H2** Island Falls Hydroelectric Station - 111 MW
- H3** Nipawin Hydroelectric Station - 253 MW
- H4** E.B. Campbell Hydroelectric Station - 294 MW
- H5** Coteau Creek Hydroelectric Station - 186 MW

IMPORT POWER PURCHASE AGREEMENTS - 290 MW

- I1** Manitoba Hydro - 290 MW

NATURAL GAS TOTAL CAPACITY - 2,434 MW

- NG1** Meadow Lake Power Station - 41 MW
- NG2** Meridian Cogeneration Station* - 228 MW
- NG3** North Battleford Generating Station* - 289 MW
- NG4** Yellowhead Power Station - 135 MW
- NG5** Ermine Power Station - 90 MW
- NG6** Landis Power Station - 78 MW
- NG7** Cory Cogeneration Station - 234 MW
- NG8** Queen Elizabeth Power Station - 527 MW
- NG9** Spy Hill Generating Station* - 89 MW
- NG10** Chinook Power Station - 353 MW
- NG11** Great Plains Power Station - 370 MW

WIND TOTAL CAPACITY - 818 MW

- W1** Riverhurst Wind Energy Facility* - 10 MW
- W2** Western Lily Wind Energy Facility* - 20 MW
- W3** Morse Wind Energy Facility* - 23 MW
- W4** Blue Hill Wind Energy Facility* - 175 MW
- W5** Red Lily Wind Energy Facility* - 26 MW
- W6** Centennial Wind Power Facility - 150 MW
- W7** Cypress Wind Power Facility - 11 MW
- W8** Golden South Wind Energy Facility* - 200 MW
- W9** Bekevar Wind Power Facility* - 200 MW

Customer-generated wind capacity - 3 MW
(NOT SHOWN ON MAP)

SOLAR TOTAL CAPACITY - 103 MW

- S1** Highfield Solar Energy Facility* - 10 MW
- S2** Pesâkâstêw Solar Energy Facility* - 10 MW
- S3** Awasis Solar Energy Facility* - 10 MW

Customer-generated solar capacity - 73 MW
(NOT SHOWN ON MAP)

COAL TOTAL CAPACITY - 1,389 MW

- C1** Poplar River Power Station - 582 MW
- C2** Boundary Dam Power Station - 531 MW
- C3** Shand Power Station - 276 MW

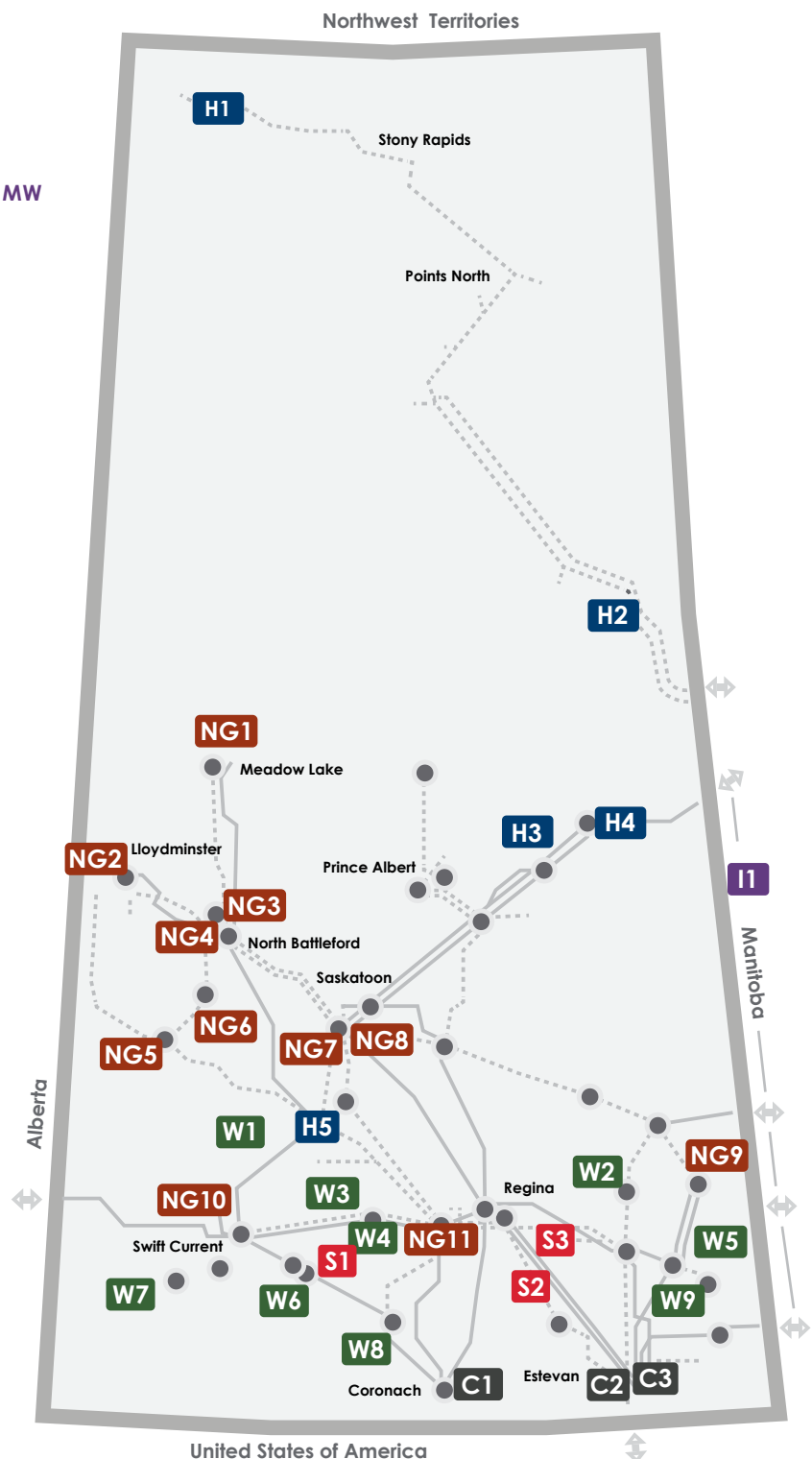
SMALL INDEPENDENT POWER PRODUCERS TOTAL CAPACITY - 33 MW (NOT SHOWN ON MAP)

(Includes flare gas, waste heat recovery, landfill gas and biomass)

TRANSMISSION

- 230 kilovolt (kV)
- 138 kV/115 kV/110 kV
- Switching station
- Interconnection

* Large Independent Power Producer





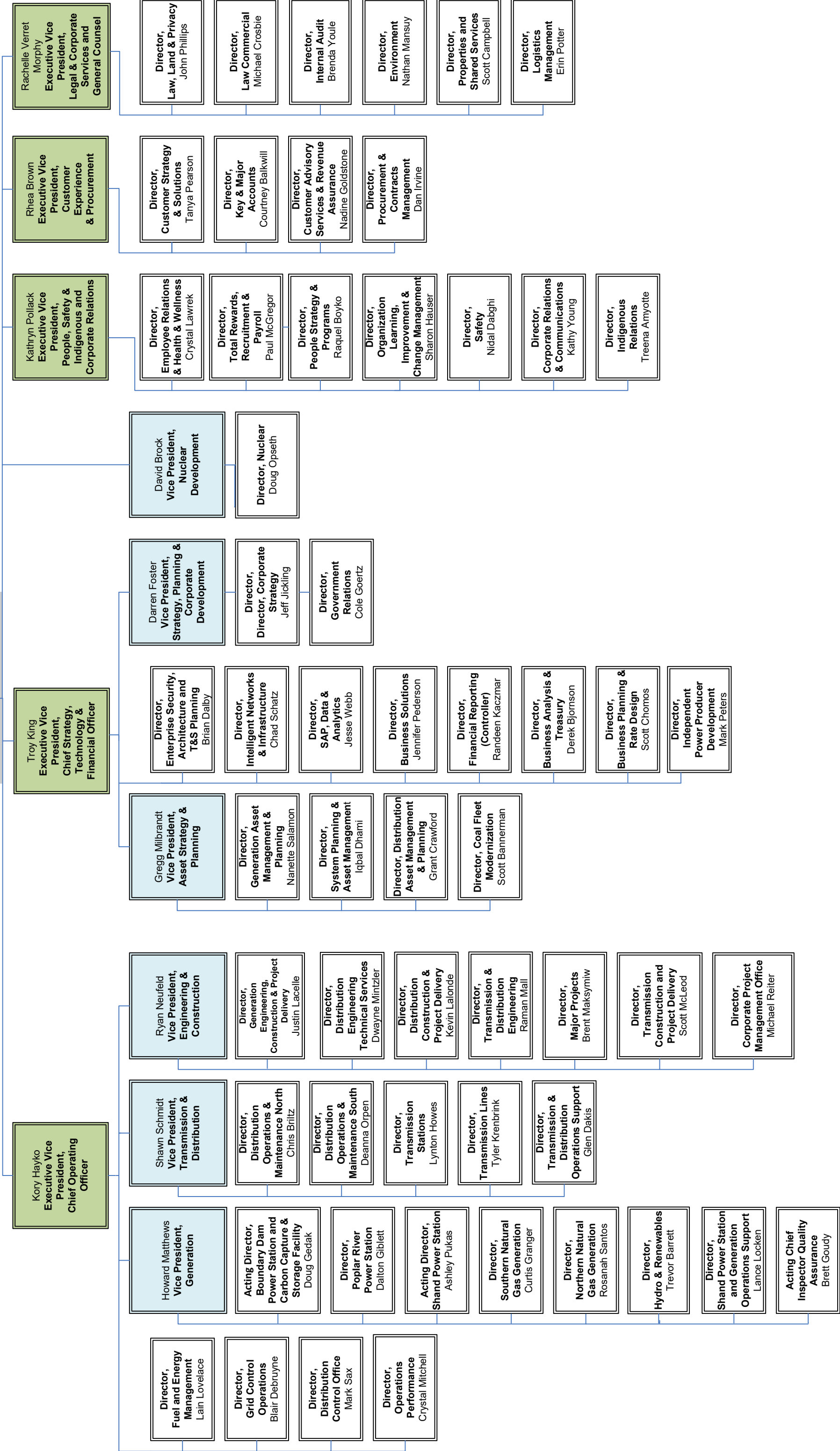
Saskatchewan Power Corporation
2025 Victoria Avenue
Regina, Saskatchewan
Canada S4P 0S1
saskpower.com

Section 2: Current organization structure



Rupen Pandya
President &
Chief Executive Officer

Manager,
Executive Office
Pam Klein McBride



Section 3: Corporate long-term and strategic plans



Saskatchewan First Energy Security Strategy and Supply Plan

saskatchewan.ca

Saskatchewan
Canada 

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Energy security means having reliable and affordable supplies of energy to ensure the uninterrupted production and availability of resources to meet people’s needs.

Saskatchewan sustainably produces food, fuel and fertilizer for our own security and the needs of others. Saskatchewan exports agri-food to over 160 countries, is the world’s second largest producer of uranium, and sends more potash into the world than any competitor. All this requires secure sources of energy.

Saskatchewan has the authority, resources, capability, and ambition for energy security. At the same time, Saskatchewan is similar to other jurisdictions in facing challenges of security of supply, meeting demand for power, and covering costs.

Saskatchewan has tremendous opportunities in electrical power generation if the right policies are pursued. But realizing that future means making tough decisions to balance costs, operability and sustainability for the provincial electrical grid. That is precisely what the *Saskatchewan First Energy Security Strategy and Supply Plan* does.

Saskatchewan’s transmission infrastructure needs to be built to anticipate future resource projects. Utilities have historically been prepared to maintain reliability and build transmission for specific customer demand. But policy direction is required to facilitate long-term economic growth for resource development and community energy security. The *Saskatchewan First Energy Security Strategy and Supply Plan* provides that policy direction.

In Saskatchewan, electricity has often been thought of as an input to growth and not as a source of growth. As the province generates more electricity from fossil fuels, renewables and nuclear power, electrical energy can also be a source for economic growth. Clear direction is needed for SaskPower to prepare the mindset, mechanisms and markets to benefit the province from abundant electricity production.

The *Saskatchewan First Energy Security Strategy and Supply Plan* is a vision and long-term strategy for electricity in Saskatchewan that prioritizes energy security. It involves a significant change in policy and thinking for Crown energy utilities.

- **Power from Strength:** Saskatchewan will use its constitutional authority, geographic position, and natural resource strengths guided by the principles of reliability and affordability for energy security and economic growth.
- **Powering Growth:** Saskatchewan will be strategic in developing its nuclear capabilities, transmission infrastructure, resources and partnerships to further the provincial Growth Plan.

Saskatchewan First

Energy Security Strategy and Supply Plan





SaskPower partnered with more than 300 Saskatchewan companies to build the gas-fired Great Plains Power Station near Moose Jaw, awarding previously unprecedented contract values to local and Indigenous businesses.

Power from Strength

Authority to Decide

The Government of Saskatchewan has the authority to decide the future of its electricity system and energy security.

The Constitution Act, 1867 gives exclusive jurisdiction to the provinces under section 92A(1)(c): for “development, conservation and management of sites and facilities in the province for the generation and production of electrical energy.”

The Constitution assigns to provinces authority over the development, conservation and management of sites and facilities in the province for the generation and production of electrical energy. Saskatchewan will exercise this authority to develop power from our strengths.

An All-of-the-Above Approach

Reducing reliance on any single source of energy enhances resilience. Electrical utilities in provinces that rely on hydro-electric production are facing future power shortfalls; meanwhile, utilities in provinces reliant on natural gas, are subject to price volatility. Saskatchewan has diversified its sources of electricity over recent decades. Whereas power was once generated almost exclusively from coal, Saskatchewan has heavily invested in natural gas-fired and hydro-electric generation, gets more power from renewables such as wind and solar, and is exploring sustainable sources of power such as biomass and nuclear.

Natural gas accounts for about 50 per cent of the annual electricity generation in Saskatchewan.

Natural gas is the largest source of power generation in Saskatchewan and remains strategically important to overall provincial energy systems. At the same time, Saskatchewan imports over 80 per cent of its natural gas. Over the next 10 years, North American demand for natural gas-fired generation is expected to rise by an additional 10 gigawatts. Suppliers of turbines for natural gas-fired generation are already raising prices and extending timelines for delivery, and global demand for liquefied natural gas may further accelerate pressures. Saskatchewan cannot rely on a single fuel source, especially one the province does not control, as the dominant source for electricity generation.

Renewables and other low and non-emitting sources of electricity already comprise 35 per cent of provincial generating capacity. In fact, SaskPower has added 635 megawatts (MW) of wind, solar and storage capacity over the past five years. SaskPower has significant hydro generation and is invested in biomass and waste heat facilities, battery storage, and other emerging technologies. SaskPower projects such as Bekevar Wind, Awasis Solar, and the Turning Sun Solar facilities attracted investment from Independent Power Producers and Indigenous equity partnerships. These projects produce benefits that go beyond energy security, towards Indigenous economic reconciliation and community investment. All the same, wind and solar power is less reliable, requires large amounts of land to develop, and the infrastructure is relatively short-lived. The province respects growing local concerns about how extensive renewables development could impede the availability of productive farmland and be misaligned with community interests.

Coal as a Secure Bridge to Nuclear

Saskatchewan will continue to use coal-fired generation as part of an all-of-the-above approach to energy security. Ending coal-fired generation by 2030 would risk the reliability and affordability of the provincial electrical system. Extending the life of our coal-fired assets will ensure that we have reliable baseload power as a secure bridge to nuclear power generation.

There is no question as to the reliability of coal as a source for electricity generation. In fact, Saskatchewan’s coal-fired units have averaged between 79 to 86 per cent availability over the past decade. Comparatively, intermittent renewable energy sources such as wind and solar can be available as little as 20 to 25 per cent of the time. Wind has lengthy periods of nil production, solar production is minimal during short winter days, and current technology for energy storage has ‘long-duration’ at 8-12 hours, but in practice is significantly shorter. At the same time, SaskPower is forecasting electricity demand to increase by 40 to 100 per cent by 2050.



Government policy direction to SaskPower to extend the life of existing coal assets has several advantages for energy security. Saskatchewan already owns the power stations it needs to generate reliable baseload power. Maintenance and sustainment over decades by SaskPower means that provincial coal assets are ready for life-extension. We have a workforce of nearly 1,100 people who know how to operate and sustain coal power stations and mine the coal that fuels them. We have energy communities such as Estevan and Coronach with the services and supplies to maintain our power. It is a credit to these workers that Saskatchewan is in a position to extend the life of coal generation. We have over a 100-year supply of coal in southern Saskatchewan, a resource owned by the people of this province.

Clear government policy direction will ensure that SaskPower has sufficient time and resources to plan accordingly and avoid a shortfall of baseload power at the end of this decade.

» **SaskPower will extend the life of up to 1530 MW of existing coal-fired power assets beyond 2030 and out as far as 2050.**

SaskPower Coal Generation Fleet						
Community	Facility		Net Capacity (MW)	End of Service Life	Service Life with Extension	Number of Employees
Estevan	Boundary Dam Power Station	Unit 3	110	2044	2050	800
		Unit 4	139	2021	2050	
		Unit 5	139	2024	2050	
		Unit 6	284	2027	2050	
		Total:	672			
	Shand Power Station		276	2042	2050	
Coronach	Estevan Mine		-			
	Poplar River	Unit 1	291	2033	2050	300
		Unit 2	291	2031	2050	
		Total:	582			
	Poplar River Mine		-			

Nuclear Power as the Future

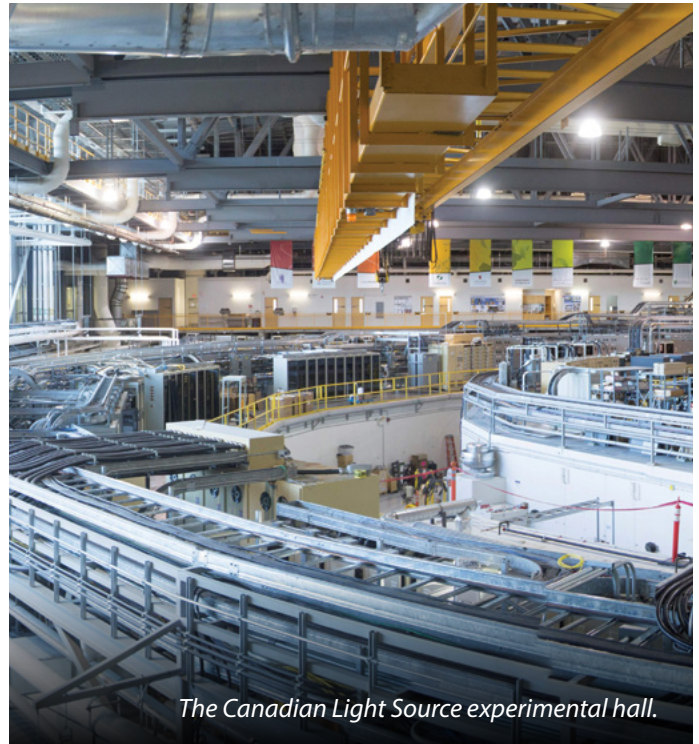
Saskatchewan is committed to building a provincial electricity system powered by nuclear energy.



Global innovation in the nuclear field now makes it feasible to add nuclear power generation to the Saskatchewan electrical grid. Through this Strategy, the provincial government reiterates its commitments to nuclear power communicated in the provincial *Growth Plan* and the *Interprovincial Strategic Plan on Small Modular Reactors (SMRs)*.

The Government of Saskatchewan will:

- » continue to examine the feasibility of two SMR units near Estevan;
- » evaluate the feasibility of large reactors and/or advanced SMRs to meet industry demand for electricity and heat to identify if either can be economically deployed in Saskatchewan.



The Canadian Light Source experimental hall.

SaskPower is working through its subsidiary, SaskNuclear, on licensing to deploy the grid-scale GE-Hitachi BWRX-300 SMR in Saskatchewan. The provincial utility is engaged with Ontario Power Generation, an experienced nuclear operator, to learn from Ontario's deployment of the first BWRX-300 reactor at its Darlington site in 2030.



The rendering shows SaskPower's chosen technology, the GE Hitachi BWRX-300 nuclear reactor.

The Saskatchewan Research Council (SRC) is invested in developing micro-reactor technologies. These comparatively smaller reactors (typically 5 -15MW) are most suited for individual community or industrial site demands. SRC Nuclear seeks to advance global knowledge of the development and deployment of nuclear micro-reactors for industrial decarbonization as well as community and commercial use. It is essential that provincial Crown corporations and ministries work closely together on planning, public engagement, investment attraction, regulatory and intergovernmental coordination for nuclear power. This means strengthening and broadening coordination in areas such as supply chain and workforce development, emergency planning, environmental review, and complementary infrastructure. This all requires clear roles and responsibilities.

The Government of Saskatchewan will:

- » coordinate provincial nuclear policy, in alignment with government-wide policy for energy security and economic growth, to ensure sufficient oversight and governance, investment attraction, supply chain and workforce development;
- » conduct a governance review to determine the optimal provincial structure and mandate for nuclear power ownership, operation, and deployment within and beyond the provincial electrical grid.

The development of nuclear power in Saskatchewan could create a new industry that generates billions of dollars in annual economic activity for the province, but will require prudent decision making, careful assessment of long-term benefits and costs, planning, and the discipline to adhere to budgets and timelines.

In 2024, 89,000 people were in the Canadian nuclear workforce, contributing \$22 billion to Canada's GDP.

Source: <https://cna.ca/2024/09/24/canadian-nuclear-industry-a-powerhouse-of-job-creation-and-economic-growth/>

As Saskatchewan bridges to a nuclear future and builds the infrastructure to move this new source of electricity to businesses and homes, it will enhance provincial sustainability. The province will reduce greenhouse gas emissions at a pace that prioritizes reliability and affordability for energy security.

- » **SaskPower aims to reduce emissions towards a carbon neutral electricity sector by 2050.**



Construction activity at the Great Plains Power Station peaked in 2023 with more than 700 workers on site each day.



The 200-kilometre transmission line, connecting the Pasqua Switching Station east of Moose Jaw to the Swift Current Switching Station was completed in 2019, taking 200,000 work hours to construct the line.



Powering Growth

Transmission Infrastructure

Transmission infrastructure is crucial to energy security and economic growth. Governments have an interest in new or expanded transmission infrastructure to improve grid reliability, attract investment to resource projects, and generate revenue. Government must be willing to consider public investment in transmission infrastructure where there is an overriding public policy interest for energy security and economic growth.

Saskatchewan is deepening cooperation with its neighbours to explore strengthened transmission networks. For example, Alberta and Saskatchewan signed a memorandum of understanding in 2024 to work together on nuclear power, grid reliability, and industrial decarbonization. Saskatchewan is deepening interconnections with markets in the United States to prepare for the potential to further export power.

In Saskatchewan:

- Intra-provincial transmission reinforcement is needed for safety and reliability.
- Northern transmission infrastructure is needed for provincial energy security and economic growth.
- Interprovincial and international transmission infrastructure is needed to enhance the resilience of the provincial electrical grid and to enable the export of excess power for revenue to sustain power systems.

Transmission in Saskatchewan must be reinforced to renew aging infrastructure as well as fulfill the buildout of renewables, flare-to-gas power projects, natural gas-fired generation, and life-extended coal assets. These infrastructure investments will help diversify and integrate a mix of all-of-the-above generation sources as well as mitigate risks from power outages during extreme weather events.

SaskPower will

- » invest in transmission infrastructure to ensure safety, reliability, and regulatory compliance, as part of its annual capital sustainment program.

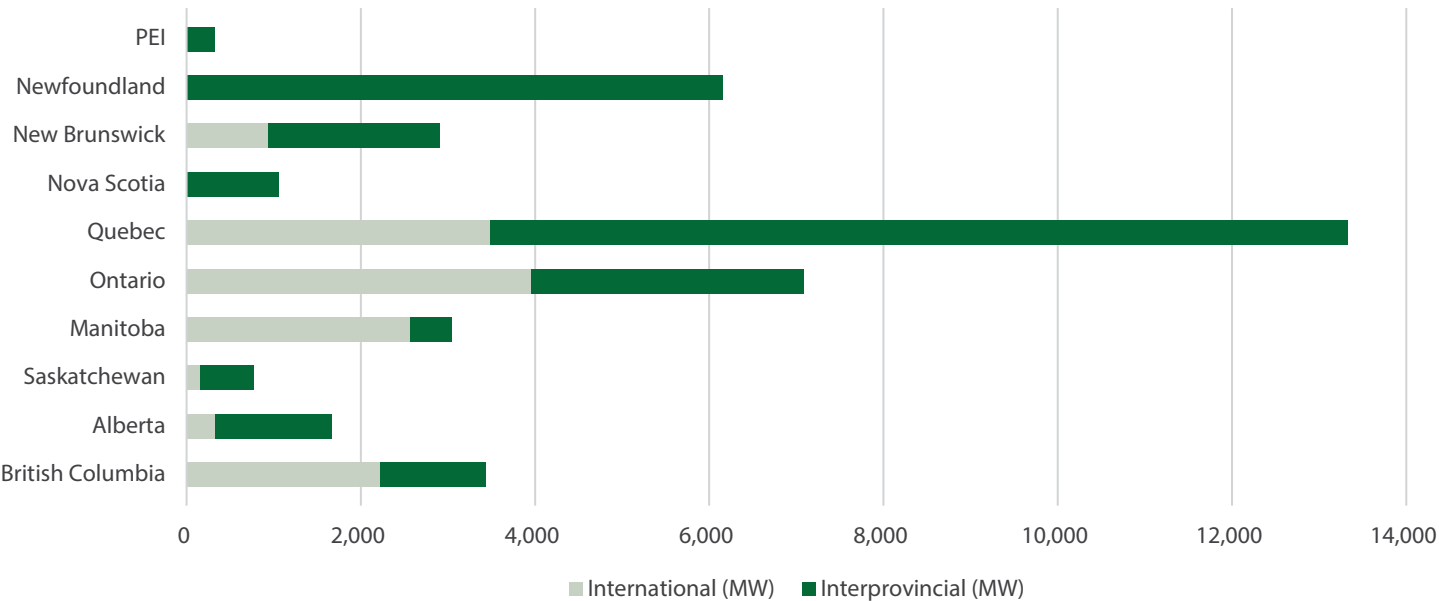
Saskatchewan has two electricity grids: mostly south and some north. There is no connection between these grids within the province. In order to get power into the northern system, electricity is wheeled into Manitoba east of the E.B. Campbell Hydroelectric Station and re-enters Saskatchewan near Flin Flon/Creighton. On the western side of the province, there are no large lines north of Meadow Lake. The current state of northern transmission infrastructure has implications for energy affordability for communities, the development of critical minerals, and provincial energy security.

Transmission interties between neighbouring provinces help to mitigate unplanned shortages and manage the electricity system across increasingly diverse power sources. The more interties, the more resilient the electrical grid. The McNeill Converter Station on the Alberta-Saskatchewan border currently has capacity to transfer only 150 MW between provinces; given that this is the only tie between the west-east systems in Canada, there may be a national interest to build this or other east-west interties at a larger capacity.

The Government of Saskatchewan will:

- » identify transmission projects of priority to Saskatchewan for energy security and economic growth, to complement the business case and forecasted return on investment for any specific transmission infrastructure project;
- » advocate for federal money to be invested in Saskatchewan for intra-provincial and inter-jurisdictional transmission to enhance reliability, affordability, energy security, and economic growth.

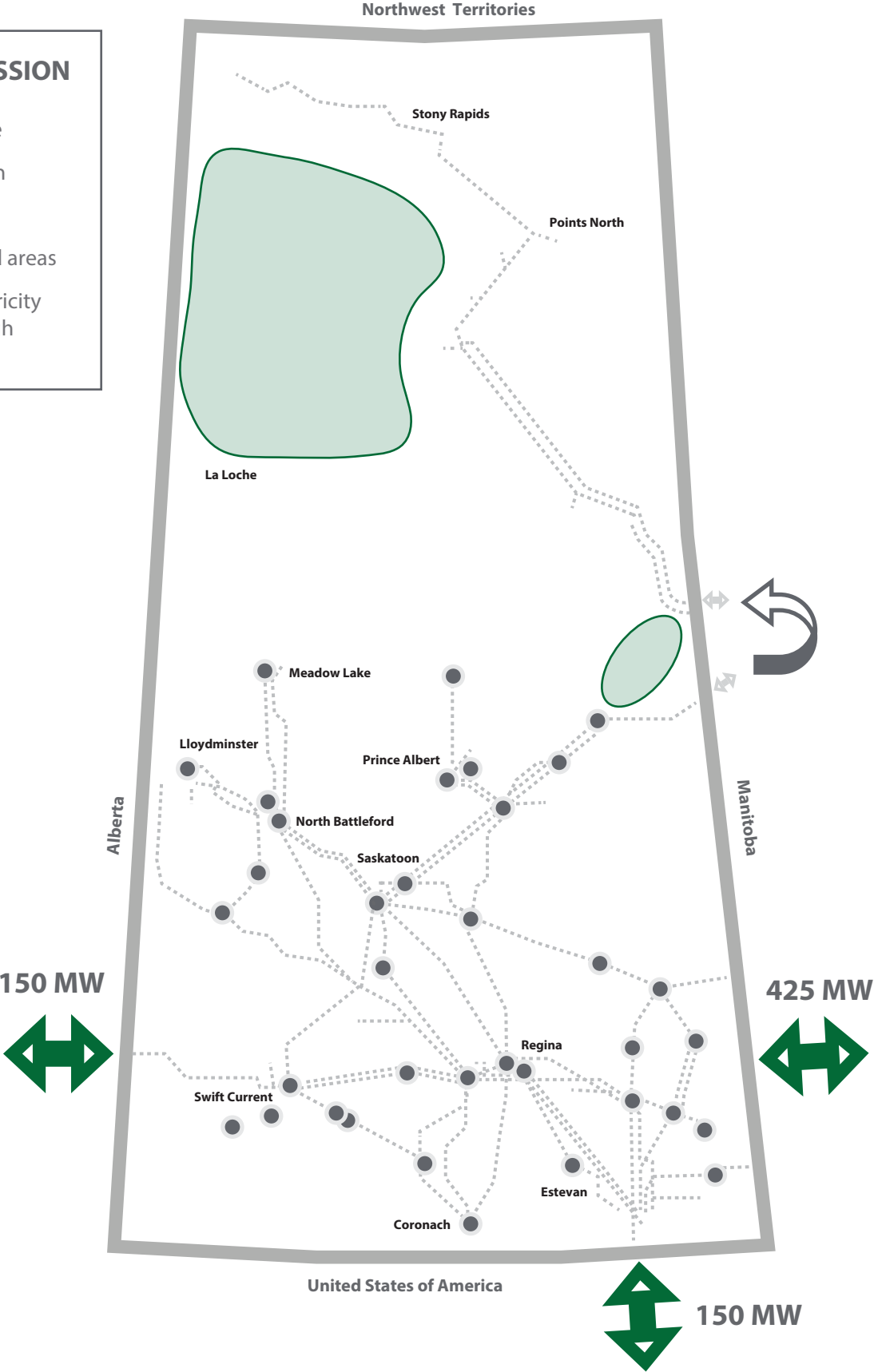
Intertie Capacity in Provinces



Saskatchewan Transmission Infrastructure

EXISTING TRANSMISSION

Transmission line

Switching station



SaskPower employees on transmission lines.

Saskatchewan stands at the centre of the North American electrical grid. To the west of Saskatchewan is a global source for secure oil and gas reserves in Alberta and British Columbia; to the north, there are rare earths plus oil and gas; to the east, some provinces are facing power shortfalls to meet demands from manufacturing and knowledge economies. South of Saskatchewan is an interconnected network of electricity markets in the United States where electricity demand is forecasted to double.

Saskatchewan's ability to be at the centre of power in North America is currently limited by being a relative power island. Intertie capacity is limited to 425MW with Manitoba, 150MW with Alberta, and 150MW to the United States.

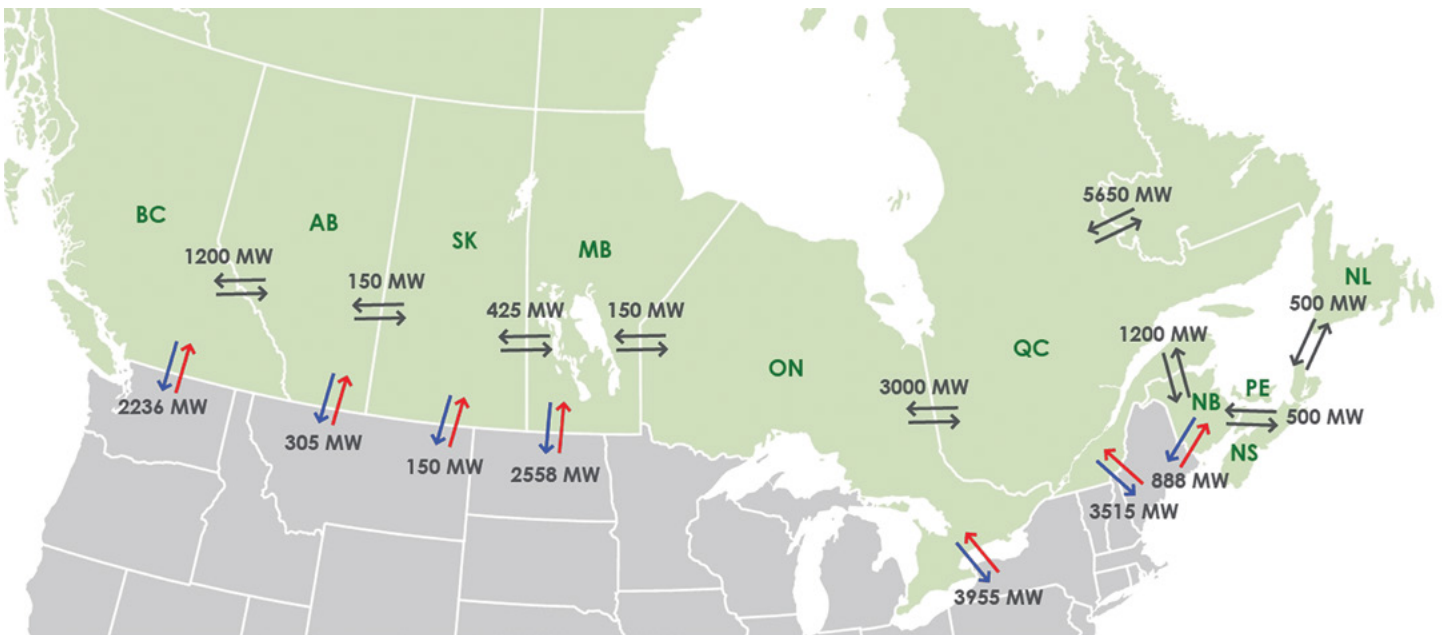
As Saskatchewan extends the life of its coal assets for immediate energy security and builds nuclear assets for future power, capacity may exceed demand. Expanded interconnections with neighbouring jurisdictions could enable power exports for commercial revenue. SaskPower is already expanding total intertie capacity to the United States Southwest Power Pool from 150 MW to 650 MW by 2027. This better connects Saskatchewan with electricity markets spanning 14 states. Further connections with Manitoba could enable additional export to the U.S. mid-west. Exporting power for profit by way of firm capacity would require cooperation between power authorities and governments.

Exporting power for profit is not simple. Power can be sold on a spot market, where there is risk of price volatility, or through firm contracts, where power must be available. Activity in power markets requires sufficient market intelligence and capacity. Fortunately, Saskatchewan has time to develop the surplus power, transmission infrastructure, and market intelligence that would be required for export. What is needed is a clear policy direction to pursue electricity export revenues.

The Government of Saskatchewan will:

- » direct SaskPower to explore options for exporting excess energy for revenue;
- » collaborate with neighbouring jurisdictions to explore stronger intertie capacities;
- » establish appropriate provincial policies, regulatory systems, and corporate structures to facilitate electricity sales, as additional exports are planned.

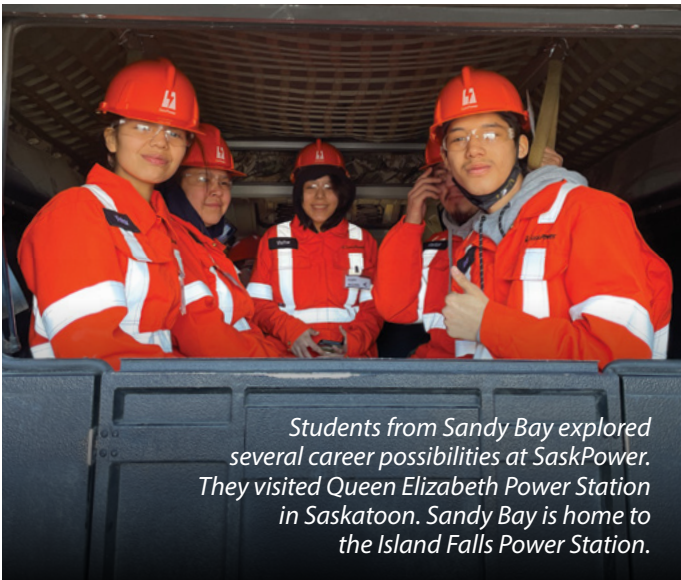
Map of Provincial Intertie Capacity (MW)



Data Source: https://www.rec-cer.gc.ca/en/data-analysis/energy-markets/market-snapshots/2024/market-snapshot-new-canadas-energy-future-net-zero-analysis-the-role-of-inter-provincial-transmission-expansion.html?utm_source=cerwebsite&utm_medium=rss&utm_campaign=fall_clicks&utm_id=4563456&wbdisable=true

People and Partnerships for Growth

Saskatchewan needs people and partnerships to accomplish its strategic objectives in the *Growth Plan* and through this strategy.



Students from Sandy Bay explored several career possibilities at SaskPower. They visited Queen Elizabeth Power Station in Saskatoon. Sandy Bay is home to the Island Falls Power Station.

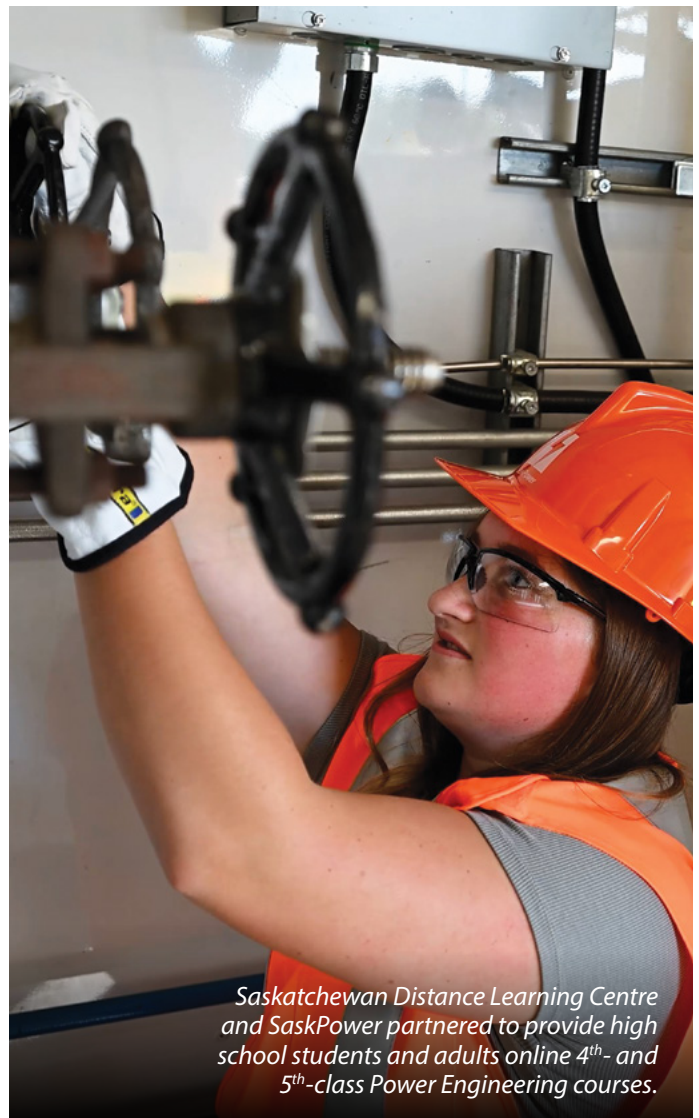
Extending the life of coal-fired electricity generation may incentivize new investments and additional economic benefits. This could include further investments in research and education in a mix of energy systems. Saskatchewan will need construction, engineering, and manufacturing labour and businesses for the electricity sector. This could include the attraction of data centres and related knowledge economy businesses that demand reliable baseload power. The province will have additional power to supply the demand of new and growing economic sectors.

Saskatchewan may also attract next generation carbon capture technologies, especially from the oil sector. Carbon dioxide-based enhanced oil recovery (CO₂-EOR) is an important pillar of oil production in Saskatchewan. To further enable EOR, the Ministry of Energy & Resources is clarifying policy questions such as surface rights access and pore space ownership. Meanwhile, SaskEnergy is pursuing further Crown sector capacity to support the transportation and storage of carbon.

Saskatchewan needs an estimated 2,500 – 3,500 skilled workers, mostly in the trades, to build and operate nuclear energy. Skilled trades will account for the largest share of Saskatchewan's future nuclear workforce. Even with SMRs being constructed and deployed in the 2030s, education and training will take years of preparation. Tradespeople working in the nuclear sector often must be nuclear qualified and could work in other sectors. For example, overlapping trades for nuclear and mining include electricians, boilermakers, pipefitters, and ironworkers. Hiring and retaining skilled tradespersons could be challenging due to competition across sectors and jurisdictions, so we need to act now.

The Government of Saskatchewan will:

- » deliver an 'Energy and Mines – Energy Production 20' high school elective course that covers nuclear, coal, natural gas, renewables, and Saskatchewan-relevant electricity content to be delivered by Saskatchewan Distance Learning Centre and made available to all Saskatchewan school divisions and schools;
- » ask the University of Saskatchewan, University of Regina, and Saskatchewan Polytechnic to take a leadership role in training for nuclear power through collaboration and partnerships with each other and with leading national and international institutions;
- » examine policy changes for simplified pathways for skilled trades training through regional colleges, Indigenous institutions, organized labour, and on-the-job training to meet future demands for the construction of nuclear power plants.



Saskatchewan Distance Learning Centre and SaskPower partnered to provide high school students and adults online 4th- and 5th-class Power Engineering courses.



The Rose Valley Wind and the Southern Springs Solar facilities will bring 300 megawatts of renewable power to Saskatchewan's power system. These facilities have the highest level of Indigenous ownership for wind and solar projects of their sizes in the province to date.

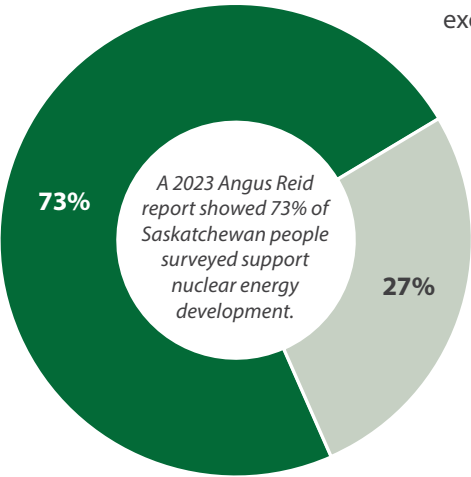
SaskPower is working with Indigenous nations as well as organizations such as the First Nations Natural Resource Centre of Excellence to establish a framework for inclusion in future energy projects. Indigenous equity investments, culturally-relevant workforce training and employment opportunities, and increased procurement from Indigenous-owned businesses will help deepen partnerships between the province and Indigenous communities.

SaskPower will

- » prioritize Indigenous partnerships, procurement from Indigenous-owned businesses, and the training and hiring of Indigenous peoples in the development of electricity projects.

Saskatchewan has the highest levels of public support for nuclear energy in the country. With the second largest uranium reserves in the world, Saskatchewan people have been mining and milling nuclear fuels for decades. Our post-secondary and research

institutions display excellence in medical isotopes, nuclear waste management, as well as mining and advanced manufacturing research. Saskatchewan is well positioned to be a leader in nuclear power production, supply chains and workforce training.



As Saskatchewan becomes more advanced in its nuclear capabilities, the province will capitalize on its existing strengths to build an innovative nuclear sector of the provincial economy. This means Saskatchewan-based businesses contributing to global supply chains for goods and services in the nuclear industry.

Saskatchewan aims to be a leader for nuclear power in Western Canada and a global centre for excellence in nuclear research and training. This builds upon historic investments in the Sylvia Fedoruk Canadian Centre for Nuclear Innovation and the Canadian Light Source synchrotron, as well as in nuclear fuels mining, milling, conversion, fabrication and transportation. The Global Institute for Energy, Mines and Society – a collaboration between the University of Saskatchewan (U of S), University of Regina (U of R), and Saskatchewan Polytechnic – will feature nuclear energy prominently in its mandate. Meanwhile, all three institutions are pursuing research chairs and new facilities in nuclear engineering, safety and advanced research.

SaskPower will invest:

- » \$3.3 million to establish two Industrial Research Chairs in Nuclear Engineering, one at the U of S and one at the U of R, in partnership with the national University Network of Excellence in Nuclear Engineering;
- » \$3.0 million to establish two Fedoruk Centre Nuclear Research Chairs; one at Saskatchewan Polytechnic and one at First Nations University of Canada;
- » Up to \$4 million to establish the SMR Safety, Licencing and Training Centre and construct two SMR flow test loops at Innovation Saskatchewan's Research and Technology Park on the University of Regina campus.

The federal government has shown extensive interest of late in electricity policy and energy corridors. Saskatchewan needs the federal government to recognize how secure provincial electricity systems make the country more resilient. There may be creative financing options that include private sector capital and Indigenous equity investments to accelerate and de-risk investments in nuclear power and transmission infrastructure. Investing in national strengths such as transmission and nuclear could further national economic growth.

The Government of Saskatchewan:

- » calls upon the federal government to invest in 75 per cent of the costs for the first nuclear reactor in the province;
- » calls upon the federal government to work with provinces on fiscal mechanisms for investments in nuclear power, nuclear supply chains and workforce development, and for a national nuclear industry that delivers domestic energy security and global exports;
- » calls upon the federal government to invest in intra-provincial and inter-provincial transmission infrastructure for benefits such as critical mineral production, community energy security, grid reliability, and national economic growth.

Saskatchewan for Energy Security and Economic Growth

Energy security requires strong and clear government policy. The *Saskatchewan First Energy Security Strategy and Supply Plan* is a vision and long-term strategy for electricity in Saskatchewan that prioritizes energy security. This vision is guided by the twin pillars of reliability and affordability.

Saskatchewan has the resources, expertise, and proximity to produce enough electricity for the province's own use and to help meet the demand of others. Past investments in mining, agriculture, oil and gas, and advanced manufacturing make the province an industrial and export leader. The Province is fortunate in its geographic place in North America, abundance of natural resources, and people for innovation. Saskatchewan has the networks and reputation to export goods, recruit talent, and attract investment – including in the electricity sector. With a vision for being at the centre of power, provincial energy can be available not only to augment the Growth Plan, it can also be a source for growth.



The Canadian Light Source is Canada's national synchrotron light source facility, located at the University of Saskatchewan.

Section 4: Current supply plan

FUTURE NEW GENERATION PROJECTS				
Project name	Net capacity (MW)	Fuel source	Ownership	Estimated commissioning year
Aspen Power Station	370	Natural gas	SaskPower	2027-28
Rose Valley Wind Energy Project	200	Wind	IPP	2027-28
Seven Stars Wind Energy Project	200	Wind	IPP	2027-28
Southern Springs Solar Energy Project	100	Solar	IPP	2027-28
Iyuhána Solar Energy Project	100	Solar	IPP	2027-28
Coleville Gas Generating Project	27	Natural gas	IPP	2027-28
North Portal Gas Generating Project	27	Natural gas	IPP	2027-28
SEEP Gas Generating Project	25	Natural gas	IPP	2027-28
Steelman Gas Generating Project	23	Natural gas	IPP	2027-28
Viewfield Gas Generating Project	23	Natural gas	IPP	2027-28
Flying Dust Gas Generating Project	20	Natural Gas	IPP	2028-29
DEEP Geothermal Energy Project	5	Geothermal	IPP	2028-29

Section 5: Most recent economic report for Saskatchewan prepared by independent third party

Provincial Economic Forecast

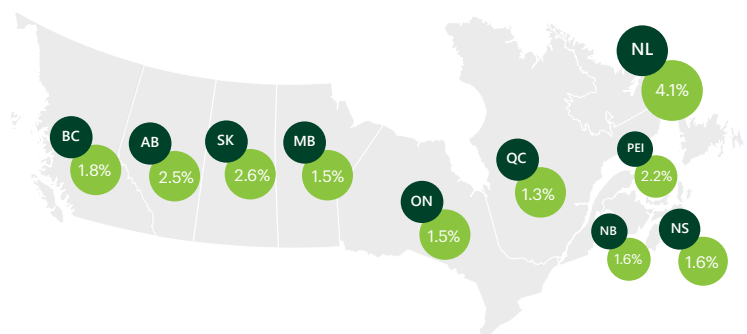
The New “R-Word”... Resilience

December 16, 2025

[Jump to: BC | AB | SK | MB | ON | QC | NB | NS | PE | NL | Forecast Table](#)

- Relative to our September projection, we’ve upgraded our 2025 growth forecasts across most regions, partly on the back of data revisions that showed economies entering the year with stronger momentum than expected. We continue to see PEI, AB, SK and NF as growth leaders this year, lifted by goods-producing industries. Meanwhile, QC, MB and ON are the likely laggards, weighed down by the trade war.
- For 2026, we see commodity-producing provinces outperforming again, but their margin of outperformance is likely to shrink amid moderately lower commodity prices, most prominently crude oil. Meanwhile, with the trade war proving less damaging than initially feared, provinces more geared to U.S. trade – like ON, MB, QC, and NB – have seen upgrades to their 2026 growth forecasts.
- Provincial exports have improved mildly since the peak of the trade shock in Q2-25, but limited trade-data access has clouded recent recovery trends. We assume that current tariff rates as well as the USMCA exemptions remain in place over the forecast horizon. The outcome of USMCA renegotiations is a risk to the outlook.
- Job markets in most provinces have turned in a more resilient performance than we had expected in September. Downside surprises in unemployment rates have been most pronounced in ON, AB, QC, NB, and PEI. While we could see job markets stumble again over the next few months, we’re expecting unemployment rates to broadly peak by Q1-2026 before drifting lower thereafter.
- Significant regional variations will exist as Canada’s housing market continues its gradual improvement next year. Price growth is likely to lag significantly in Ontario and, to a lesser extent, B.C., reflecting loose supply/demand conditions. In contrast, Quebec and the Prairies are likely to see firmer price gains, underpinned by tight conditions, and decent affordability (in the Prairies).
- Population growth is projected to continue to decelerate sharply across provinces in response to recent changes in federal immigration policy. These changes are constraining labour force growth, limiting upside in provincial jobless rates and pressuring down rents and to a lesser extent consumer spending. Provinces most exposed to these effects include ON, B.C. and QC due to their higher non-permanent resident (NPR) shares.

Provincial Real GDP Growth Forecast (2025)



Source: TD Economics. Forecast as of December 2025.

For more details on our national forecast see our [Quarterly Economic Forecast](#)

British Columbia

We forecast B.C.'s real GDP growth to pick up in 2025 from last year's sluggish pace thanks to recent strengthening in key economic indicators. Output will likely fall short of its long-term average in the near-term, but it's still expected to exceed the national average growth rate.

Contrary to our expectations, B.C.'s consumer spending has continued at a brisk pace despite still-high debt levels and decelerating population growth. In fact, the province leads nationally in inflation-adjusted retail spending this year, supported by moderating inflation and lower interest rates (Chart 1). Subdued spending in 2024 also provided a favourable baseline for growth this year. Looking ahead, we expect some of the current momentum to be sapped as employment growth cools and population growth continues to rein in.

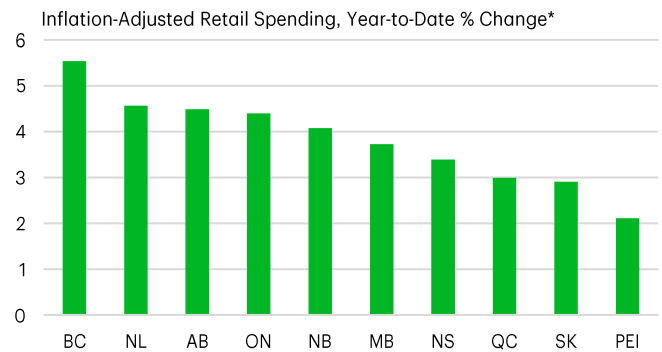
A sharp turnaround in residential construction has also been a key growth contributor this year. Housing starts have trended swiftly higher and are currently running above their 10-year average. And while resale activity still sits approximately 20% below the decade average, a recent firming in sales bodes well for a pickup in 2026. We see resale volumes rising by a nation-leading 15% next year.

The external picture is more mixed, as U.S. tariffs and broader uncertainty still continue to weigh on exports and business investment. Among B.C.'s advantages is a diverse mix of trading partners. But as Chart 2 shows, B.C.'s exports to markets outside of the U.S. lag behind the export rotation recorded nationally. The imposition of new tariffs and recent rise in lumber duties have hampered forestry exports, while LNG exports are being offset by declining coal shipments.

Four major projects with a combined estimated value of \$40 billion, including two major LNG expansions, have been fast-tracked by the federal government. We do not include these into our medium-term forecast, but they do present an upside risk if they do indeed move forward.

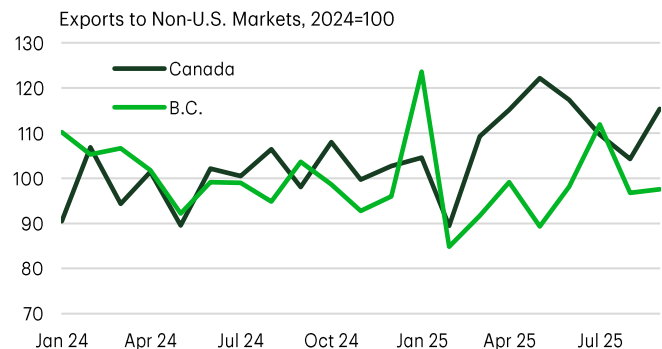
In its mid-year fiscal update, the government forecasts the FY 2025/26 deficit to be \$11.2 billion (2.5% of GDP), roughly unchanged from February's projections. B.C.'s fiscal position has weakened in recent years, leaving less flexibility to respond to growing competition for capital and near-term economic shocks. Program spending is projected to flat-line next year, which may constrain growth in public services that have otherwise enjoyed robust growth over the last two years.

Chart 1: B.C. Households Have Kept Their Wallets Open



*Data as of September 2025. Source: Statistics Canada, TD Economics.

Chart 2: B.C.'s International Export Rotation is Lagging



Source: Statistics Canada, TD Economics.

British Columbia Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.8	1.5	1.7
Nominal GDP	4.3	4.0	3.8
Employment	1.2	0.4	0.7
Unemployment Rate (%)	6.2	6.1	5.6
Housing Starts (000's)	42.7	41.4	44.7
Existing Home Prices	-2.5	3.6	3.4
Home Sales	-5.2	15.1	13.0

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Alberta

Alberta's economy is expected to grow at a trend-like pace in 2025, before taking a small step back next year. Still, the province appears positioned to outperform most other jurisdictions. Economic activity has been helped by momentum in the energy and construction sectors, along with steady consumer spending gains. These factors are helping to counterbalance weakness in U.S.-oriented sectors like manufacturing and wholesale industries.

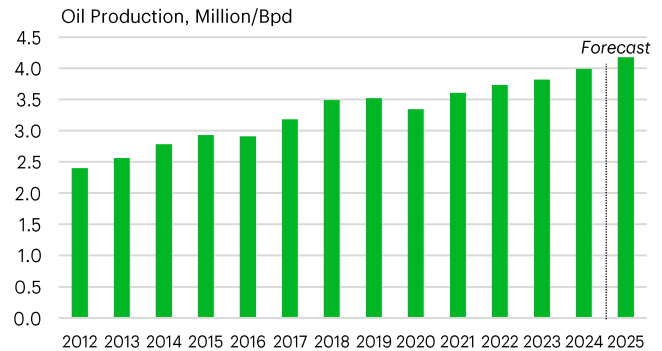
Improved market access, spare pipeline capacity, and sturdy global demand for oil have kept Alberta's heavy crude production near record levels (Chart 1). The energy sector will continue supporting growth in 2026, but softer oil prices will likely slow the pace of new drilling and industry capital spending. The lower price of crude is also weighing on Alberta's fiscal position, with the deficit now projected at \$6.4 billion, up from the \$1.4 billion shortfall estimated in the February Budget. Western Canada Select's (WCS) recent outperformance over WTI has narrowed its discount to \$10-12/bbl, partially cushioning the negative impact on government revenues.

Energy prospects may brighten if proposed pipeline expansions – adding up to ~600k/bpd to capacity over the next two years – move forward. This is in addition to the much-awaited MOU reached between Alberta and the federal government that sets out the necessary conditions to approve one or more new oil pipelines with at least 1 million/bpd of new capacity. While this deal represents a significant step forward, we would only incorporate the project into our projections when a private-sector proponent is secured and other MOU conditions are met.

Over 2025, Alberta's unemployment rate trended higher as labour force gains outstripped still-solid job growth. In November, the unemployment rate dropped sharply to 6.5%, suggesting a potential shift as labour force growth shows signs of moderating. Looking ahead, we expect the unemployment rate will gradually trend lower through 2026 as a continued deceleration in population growth reduces new labour supply (Chart 2).

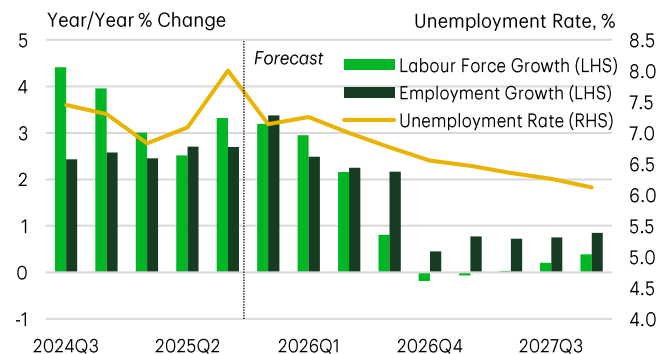
Indeed, Alberta's above-average population growth rate has helped drive solid inflation-adjusted spending by households. Other factors like lower inflation and government tax relief have also supported outlays. Moreover, the influx of newcomers has buoyed housing demand and residential construction, evidenced by the 20% year-to-date (YTD) increase in housing starts. This is reflected in our Alberta home sales forecast that sees growth of 6% next year.

Chart 1: Alberta's Oil Production on Pace for a Record Year



Source: Alberta Energy Regulator, TD Economics.

Chart 2: Alberta's Unemployment Rate to Trend Lower as Labour Force Growth Slows



Source: TD Economics.

Alberta Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	2.5	1.9	2.1
Nominal GDP	4.3	3.8	4.0
Employment	2.8	1.8	0.8
Unemployment Rate (%)	7.3	6.9	6.3
Housing Starts (000's)	56.8	52.2	43.0
Existing Home Prices	3.7	4.4	4.3
Home Sales	-7.3	5.9	10.7

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Saskatchewan

Recent data has reinforced that Saskatchewan's economy is positioned to be among the provincial leaders in GDP growth this year. Looking ahead, the province will likely see 2026 growth moderate to a more sustainable pace, but still placing it above the national average.

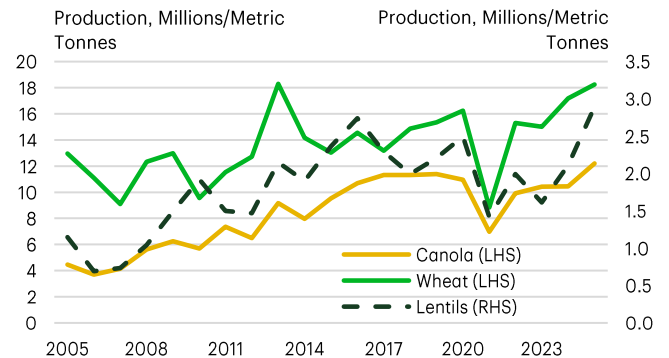
Official crop statistics for 2025 revealed a 13% increase in Saskatchewan's total crop production, surpassing our projections. This robust growth is enough to boost headline GDP by up to one percentage point in 2025. Both canola and lentil harvests have hit record levels, while wheat production is nearing an all-time high (Chart 1). The agricultural forecast for 2026 is more cautious, as yields likely moderate and Chinese duties on \$5 billion worth of canola products continue to weigh. Canola exports to China – Saskatchewan's second largest trading partner – are down by 40% this year, while wheat exports have been able to take up some of the slack.

Elsewhere in the commodity space, production and shipments of potash and uranium have turned in solid performances so far this year. Looking ahead, prospects for steady 3% global growth are expected to underpin healthy demand for these commodities in 2026-27, though a near-term easing in prices may limit some upside to activity. On the other hand, oil production and exports are on track to contract moderately this year. And next year's performance is likely to stay relatively muted, as weaker prices and oversupplied markets dampen industry profitability.

The construction sector is poised for a second consecutive year of double-digit growth in 2025, lifted by surging residential and non-residential spending. The pace of construction growth in 2026 will likely ease, but to a still-sturdy rate. Notably, the government plans to ramp up capital spending in coming years, while ongoing work on major private investment projects adds a mild tailwind to the province's economic growth.

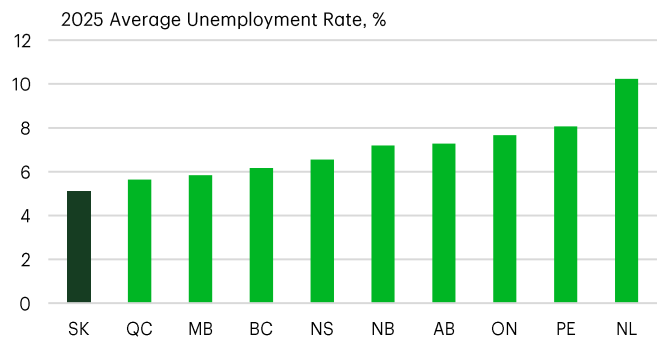
Saskatchewan's labour market has been a clear outperformer, boasting the lowest unemployment rate among jurisdictions (Chart 2). Robust employment growth has supported real wage gains and has pushed inflation-adjusted retail spending growth ahead of most provinces. Still, the recent hiring strength has been driven almost entirely by the public sector. Next year, we expect to see a rotation back to private-sector-led hiring with the unemployment rate likely holding around current levels.

Chart 1: Strong Production of Key Crops Drives Agricultural Sector Strength in 2025



Source: Statistics Canada, TD Economics.

Chart 2: Saskatchewan's Labour Market Among the Healthiest in the Country



Source: Statistics Canada, TD Economics.

Saskatchewan Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	2.6	1.7	1.7
Nominal GDP	5.0	3.4	3.8
Employment	2.6	1.4	0.5
Unemployment Rate (%)	5.0	5.1	5.1
Housing Starts (000's)	6.8	5.6	5.0
Existing Home Prices	8.3	5.2	5.1
Home Sales	1.1	8.4	5.4

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Manitoba

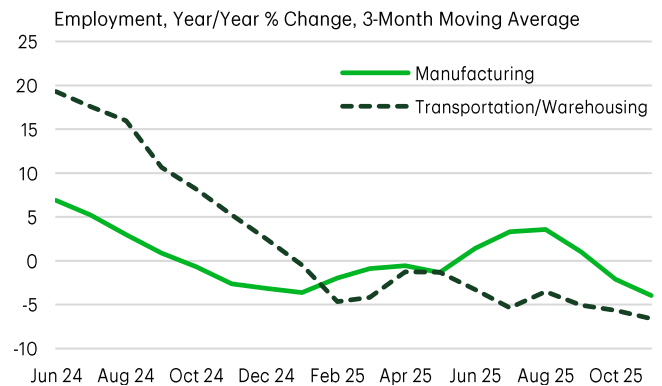
We're tracking a 2025 real GDP gain in Manitoba that's a tick below the 10-year average. Despite U.S. tariffs having minimal direct impact on Manitoba's exports, the hazy trading environment has likely impacted confidence and activity in industries most reliant on the U.S. Indeed, employment in manufacturing and transportation/warehousing is down 2% on average so far in 2025 (Chart 1) and has yet to show signs of turning around unlike trends being observed nationally. On the flipside, we see the public sector making a large contribution to growth this year, consistent with hiring trends. And agricultural production likely advanced around 5% this year (despite Chinese tariffs on canola products), driven by gains in rye, corn and soybeans.

With the province having absorbed the initial blow from the trade war, we anticipate that its U.S.-levered industries will (belatedly) begin to grind out a modest recovery next year, consistent with continued solid U.S. expansion. Interprovincial trade is especially important to Manitoba. The province has its own legislation removing trade barriers, while being signatory to the recent federal-provincial-territorial interprovincial trade agreement. This should also help bolster activity next year. The Port of Churchill development is on Canada's list of "transformative projects", with the federal and provincial government committing funding towards the project. If implemented, the project would enhance Manitoba's medium-term international trade. However, it's in its very early stages, with significant hurdles still to overcome.

Despite the soft economic backdrop, overall hiring has preceded at a firmer pace in Manitoba than the rest of the country, on a year-to-date basis. This has backstopped a decent consumption performance. However, with the pace of hiring likely to cool next year in line with slowing population and labour force gains, household spending should put up a more muted performance in 2026.

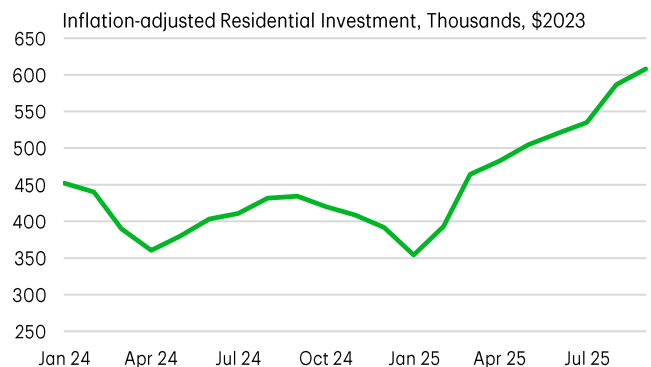
Softer hiring should also cool some of the momentum in housing demand and home price growth next year. That said, home prices are elevated, which alongside rental construction is supporting robust residential investment (Chart 2). This trend should persist next year, and provincial capital spending plans are healthy. As such, construction is likely to make another notable contribution to growth in 2026.

Chart 1: Trade War Weighing on Manitoba



Source: Statistics Canada, TD Economics.

Chart 2: Homebuilding Offering Solid 2025 Growth Contribution in Manitoba



Source: Statistics Canada, TD Economics.

Manitoba Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.5	1.3	1.9
Nominal GDP	4.0	3.5	4.1
Employment	1.7	1.2	0.7
Unemployment Rate (%)	5.8	5.5	5.2
Housing Starts (000's)	7.8	7.3	6.3
Existing Home Prices	5.9	6.3	4.3
Home Sales	3.6	2.8	4.0

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Ontario

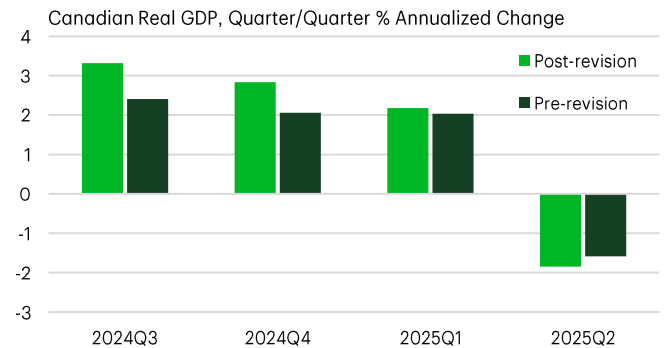
Recent data revisions suggest that nation-wide growth was about 0.5 ppts higher in 2023 and 2024 than previously thought. 2024's revision suggests that Ontario had better-than-anticipated momentum heading into this year (Chart 1). This underpins our upgraded 2025 real GDP growth forecast. Most heartening were the sizeable positive revisions to business capital spending, which suggests a less depressed investment backdrop than initially feared. However, the picture for Ontario so far in 2025 has been less than encouraging. Provincial data suggest that Ontario's economy barely grew in the first half of 2025, owing to retrenching homebuilding and plunging exports and private sector investment amid the trade war. The province did receive some good news on the latter, however, with the recent announcement that a \$3.2 billion graphite plant will be built in St. Thomas.

Industries highly levered to the U.S. are on course to subtract from 2025 GDP growth. In the manufacturing sector, recent decisions by automakers to shift production to the U.S. and not move forward with new production that was previously planned are negative for the outlook. On the brighter side, manufacturing activity excluding autos is starting to stir, with nominal sales rising in two of the last three months to October. Exports to non-us trading partners are also up 20% year-to-date. Looking ahead to 2026, we're forecasting a broader – though still mild – recovery in manufacturing activity, lifted by continued U.S. and Canadian growth. Ontario has also been relatively aggressive in removing interprovincial trade barriers, which could help manufacturing prospects.

Homebuilding in the province is very subdued (Chart 2), held back by elevated costs and years of low pre-construction sales in the GTA. Amid slowing population growth and rising inventory levels, we're forecasting another difficult year for homebuilding in 2026. In contrast, resale activity should continue rising from its low level moving forward, supported by pent-up demand, although supply/demand conditions that favour buyers will likely keep price growth cool.

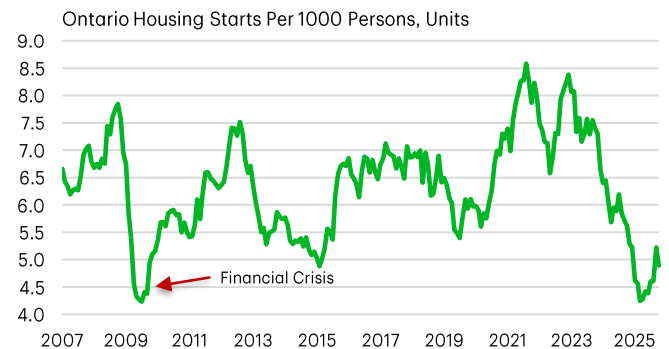
Consumption held up well in the first half. However, declining retail spending volumes suggests a softer Q3 performance. This is consistent with our expectation of modest consumption gains moving forward, as muted economic growth and impeded business confidence weighs on hiring.

Chart 1: Revisions Show Stronger Momentum Into 2025 in Canada and, Likely, Ontario



Source: Statistics Canada, TD Economics.

Chart 2: Ontario Starts Near Financial Crisis Depths by Some Measures



Source: CMHC, Statistics Canada, TD Economics.

Ontario Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.5	1.0	1.8
Nominal GDP	4.0	3.4	3.8
Employment	1.0	0.1	0.5
Unemployment Rate (%)	7.6	7.5	7.0
Housing Starts (000's)	62.1	60.7	64.1
Existing Home Prices	-3.2	0.6	3.2
Home Sales	-4.6	13.0	10.1

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Québec

Recent revisions show that Canada had better momentum heading into this year than previously thought. Some of this improvement likely took place in Quebec, supporting our upgraded 2025 annual average GDP growth forecast. However, the province is still likely to turn in a relatively weak performance this year, partially on the back of a massive 2.4% annualized contraction in Q2 GDP. Moreover, industry-based GDP data are flagging a relatively modest Q3 rebound (Chart 1).

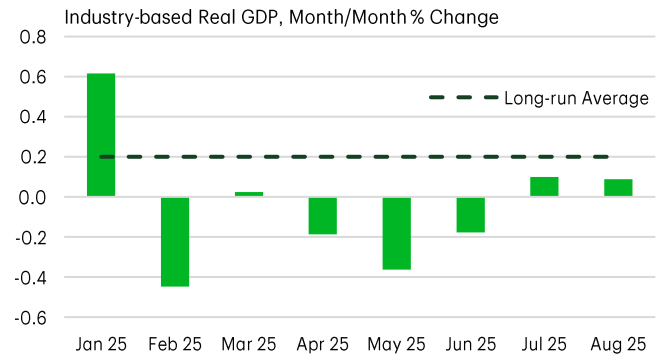
Industries levered to the U.S have driven the weakness this year, particularly Quebec's manufacturing sector. Notably, exports of aluminum to the U.S. (directly targeted by U.S. tariffs) have dropped 15% so far this year. The transportation sector strike will also weigh in the near-term.

On a positive note, manufacturing sales have managed to turn higher since May, highlighting that the worst of the initial trade shock is in the rearview. What's more, Quebec has had some success in shipping to non-U.S. markets, with exports to the EU up 27% year-to-date. This increases our confidence that 2026 will be modestly better for the province's manufacturers, assuming no major downside on trade policy materializes during the upcoming USMCA review.

Bucking the trend in external-facing portions of the economy, household spending has been solid so far this year (Chart 2). Hiring has been resilient. Households in the province are also tapping their savings to finance consumption, with the household savings rate dropping 1.5 ppts year-on-year to a still-elevated 7.9% in 2025Q2. Moving forward, an outlook for both cooling job and population growth should sap some steam from consumption next year, restraining the pace of improvement in overall GDP. On the flip side, households will see some modest support from measures in the latest fiscal update, including reduced contribution rates to the QPP, and the indexation of personal income taxes and social assistance benefits to inflation.

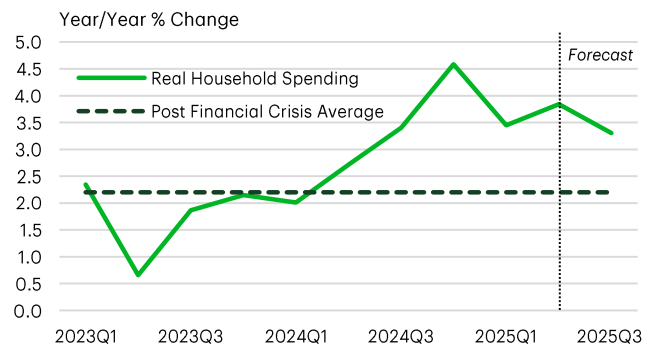
Robust housing activity has been another factor that has supported consumption. Home sales are running well above long-term norms on a per capita basis (supported by job markets), while home price growth continues to be robust. Moving forward, we continue to see solid price growth in Quebec next year, underpinned by tight supply/demand balances.

Chart 1: Monthly GDP Suggesting a Subdued Q3 Performance in Quebec



Source: Quebec Government, TD Economics.

Chart 2: Robust Household Spending Preventing Worse GDP Outcome in Quebec



Source: Quebec Government, TD Economics.

Québec Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.3	1.1	1.6
Nominal GDP	4.3	3.4	3.6
Employment	1.7	-0.2	0.2
Unemployment Rate (%)	5.6	5.7	5.5
Housing Starts (000's)	60.1	57.2	51.9
Existing Home Prices	8.3	6.9	4.4
Home Sales	8.8	4.1	1.0

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

New Brunswick

We've nudged up N.B.'s growth outlook for both 2025 and 2026, largely on the back of recent upward revisions to national growth and the province's sturdier-than-expected showing since our September projection. Average GDP growth of 1.5% this year and next is consistent with N.B.'s longer-term historical trend and puts it on track to keep pace with Canada.

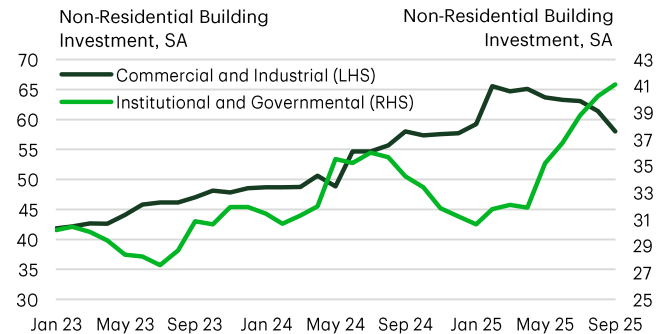
Increased infrastructure spending by the provincial government is providing a boost to construction activity. Over the past year, investment in institutional and government buildings has increased by more than 50% to reach a new record high. This is helping to offset some of the slowdown in private sector investment (Chart 1). New housing construction has also been very robust, as record-high housing starts are being fueled by strong demand for multi-unit rental properties. We expect residential building activity to moderate next year as a number of current projects reach completion. Meanwhile, resale conditions are expected to remain relatively tight, as transactions expand further and average price growth holds in the mid-single-digits.

Manufacturing, transportation, and wholesale sales – the sectors most exposed to external trade – continue to face challenges from tariffs and declining U.S. demand. This is reflected in the 8% year-to-date drop in total exports, one of the weakest showing among provinces (Chart 2). By our calculations, the contractions expected in these industries will shave around 0.3 percentage points (ppts) off of headline GDP growth this year. However, we anticipate that these sectors will record slight improvements over the remainder of the forecast horizon, as exporters continue to adapt to the U.S. tariff environment.

Elsewhere, households are showing their mettle despite the ongoing trade and job market uncertainty. Retail spending growth has been running in the middle of the provincial pack this year, helped in part by the relatively low average debt level of consumers. We do expect some of this spending momentum to wane next year as population growth continues to decelerate.

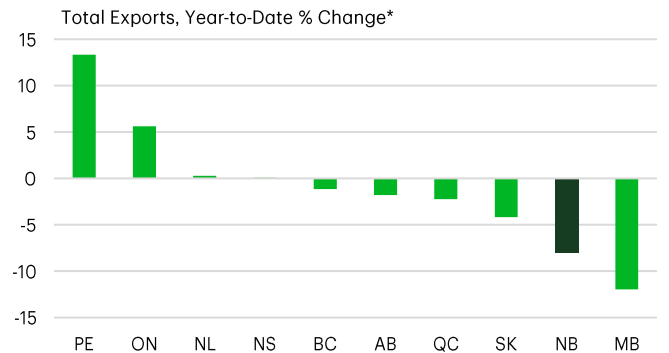
In its mid-year fiscal update, the provincial government projected a deficit of \$835 million in FY 2025/26 (or -1.7% of GDP) – the largest fiscal shortfall in 12 years. For now, the government remains on track to grow program spending by 5% next year, notably higher than most provinces.

Chart 1: N.B. Provincial Investment Bolstering Non-Residential Construction Activity



Source: Statistics Canada, TD Economics.

Chart 2: New Brunswick's Exports Challenged by Trade Headwinds



*Data as of September 2025. Source: Statistics Canada, TD Economics.

New Brunswick Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.6	1.3	1.1
Nominal GDP	3.9	3.5	3.1
Employment	1.2	0.4	0.4
Unemployment Rate (%)	7.2	7.6	7.4
Housing Starts (000's)	7.1	6.9	4.5
Existing Home Prices	5.9	4.9	4.2
Home Sales	3.4	6.3	3.0

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Nova Scotia

We've upgraded our 2025 growth forecasts for Nova Scotia, in line with significant upward revisions to Canadian GDP that show improved nation-wide momentum heading into this year. Still, while decent, growth is tracking its slowest (non-pandemic) performance in nearly a decade. This would be consistent with the cooling we've seen in job growth (Chart 1). We're estimating soft performances in finance/insurance/real estate and the public sector – in line with hiring trends. The latter comes despite the province's latest fiscal update showing a steep upward revision to FY 2025/26 program spending, on the back of healthcare.

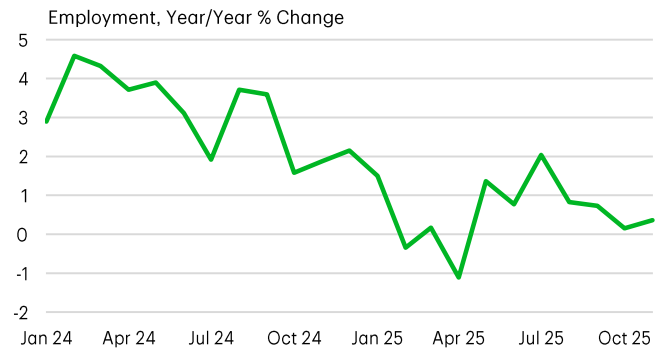
We're expecting a similarly decent growth showing for Nova Scotia next year. The province's large defense industry should receive an on-going lift from the federal commitment to invest \$80 billion in Canadian defense and indeed, we saw Canadian government capital expenditures surge in the 3rd quarter (Chart 2). What's more, military workers will benefit from pay raises offered by the federal government.

Construction activity has been making a solid contribution to GDP this year, lifted by residential and non-residential spending. 2026 should see more of the same, given highly elevated housing starts and construction of the large-scale QEII hospital development. What's more, work on the new \$2.1 billion Goldboro gold mine is expected to start next year. If it gets off the ground, the \$60 billion Wind West offshore wind project offers significant promise over the medium term, both during the construction and operation phases.

Nova Scotia's external-facing industries are holding up (even with 25% Chinese tariffs on the province's seafood products). Exports to the U.S. have been flat this year (compared to a 3% Canada-wide drop), helped by what is likely a high degree of CUSMA compliance in the tire manufacturing industry. However, a more modest gain in manufacturing is likely in 2026 (flagged by some softening momentum in sales since July) as activity in domestic trading partners is subdued.

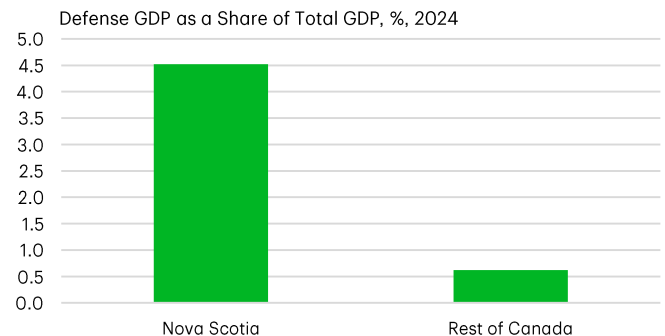
Retail sales have held up well so far this year, supported by robust wage growth. However, we see consumer spending softening in 2026, holding back the gain in GDP. Another year of weak population growth should play a role in restraining hiring below recent trends, weighing on consumption.

Chart 1: Cooling Hiring Suggests Softer 2025 GDP Growth in Nova Scotia



Source: Statistics Canada, TD Economics.

Chart 2: Nova Scotia Poised to Benefit from Defense Spending Ramp Up



Source: Statistics Canada, TD Economics.

Nova Scotia Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	1.6	1.6	1.2
Nominal GDP	4.1	4.0	3.2
Employment	0.5	-0.2	0.4
Unemployment Rate (%)	6.6	6.9	6.8
Housing Starts (000's)	9.9	8.3	6.6
Existing Home Prices	4.5	4.5	3.6
Home Sales	0.9	6.7	7.9

Source: Statistics Canada, CMHC, CREAA, Forecast by TD Economics.

Prince Edward Island

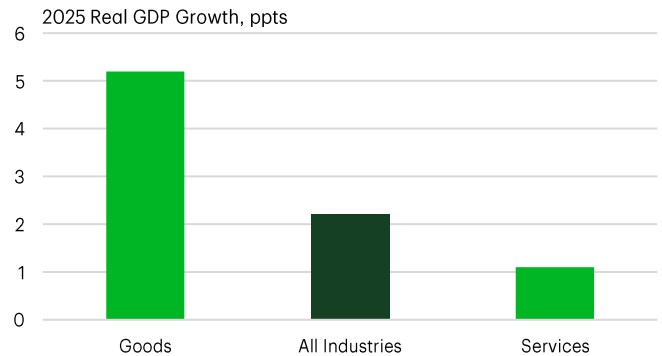
In the past decade, PEI's real GDP growth has quietly topped Canada's nearly every year, fuelled by stronger population growth. This outperformance looks to have been repeated in 2025, with the Island likely to sit near the top of the provincial growth leaderboard. The goods sector has been doing most of the heavy lifting on growth (Chart 1), despite what looks to be a down year for agricultural production, owing to a pull-back in non-potato crops. Surging construction activity has supplied the largest boost, with residential investment stoked by several years of robust population gains, and non-residential spending fuelled by government investments. We see construction making another strong growth contribution in 2026. The provincial government's recently released capital plan features a 16% jump in planned capital outlays in FY 2026/27 compared to the prior target for the same year. The Island's capital plan comes with a cost, however, as its debt-to-GDP ratio is forecast to climb to 35% in FY 2026/27 – the highest since at least FY 1986/87.

Manufacturing has also bucked the national trend, with shipments up 11% year-to-date, year-on-year, lifted by durable goods. International export growth has also been robust, both to U.S. and non-U.S. markets, on the back of food products. Tourism is another external-focused industry that's enjoyed a firm 2025 (overnight stays up 10% year-to-date), buoyed by domestic visitors and a low Canadian dollar. Next year could bring a moderation to more sustainable growth rates within these industries. We're also anticipating some firming in the loonie.

Despite the positives noted above, we're forecasting economic growth to post its weakest (non-pandemic) performance since 2015 next year. We've baked in a slowdown in public sector output growth in 2026, which is notable as it accounts for about one-third of PEI's GDP. This would be consistent with the provincial budget. The federal government also has a large presence in PEI, so federal operating spending cuts should weigh heavily on the Island. Note that the federal government accounted for 7% of the Island's GDP in 2024, compared to 2% for Canada overall.

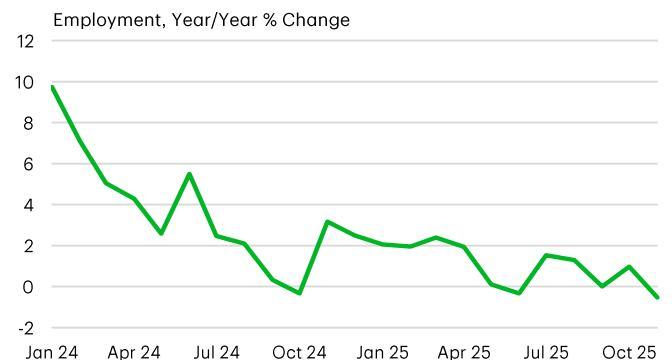
Population growth has been cooling rapidly, shifting from a 4% annual pace in early 2024 to 1.6% in 2025Q3, driven by a net outflow of non-permanent residents. We anticipate slow population growth again next year, restraining job gains and spending (Chart 2).

Chart 1: Goods-Sector Doing the Heavy Growth Lifting in PEI This Year



Source: Statistics Canada, TD Economics.

Chart 2: Job Growth Cooling in PEI



Source: Statistics Canada, TD Economics.

P.E.I. Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	2.2	1.5	1.6
Nominal GDP	4.3	3.9	3.6
Employment	0.8	0.4	0.6
Unemployment Rate (%)	8.1	8.1	8.0
Housing Starts (000's)	1.7	1.5	1.3
Existing Home Prices	2.9	5.1	3.5
Home Sales	5.6	4.0	3.9

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Newfoundland & Labrador

After several years of underperformance, N&L's economy is set to record nation-leading growth in 2025. Indeed, we upgraded our already-bullish estimate relative to September. The energy sector is the driving force, contributing to over half of estimated growth for the year. All oilfields are in operation for the first time since late-2023, which has helped push year-to-date (YTD) production volumes nearly 20% higher (Chart 1) and marking the best year for the sector since 2016. Looking ahead, with the impetus from higher oil production set to fade, we expect the province's growth rate to return back to the slow lane by 2027.

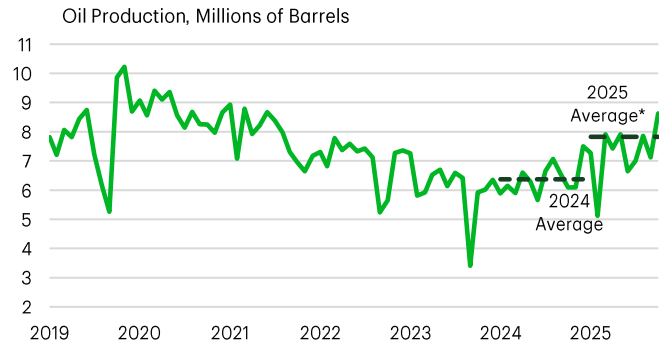
This year, the province has been better able to manage trade-related headwinds as its geographic advantage has allowed it to capitalize on global trading opportunities. Indeed, over 50% of energy shipments now head to Europe and total exports to non-U.S. trading partners are growing at the fastest pace across provinces. This relative advantage will continue to support a gradual export recovery next year.

The strong economic backdrop has also supported households, who continue to spend at a decent clip. However, we've seen retail spending cool in recent months, likely a lagged response to the slowdown in the job market. Hiring in the province has now turned negative on a year-to-date basis, with over half the province's industries expected to shed jobs this year (Chart 2). Unfortunately, conditions in the job market appear set to weaken further in the coming quarters, sending the jobless rate higher to around 11% by end-2026, and flattening thereafter.

The construction sector has been the glaring weak spot in the economy this year and activity will likely remain subdued over the remainder of the forecast horizon. Housing starts have fallen this year, pressuring real residential investment lower. Meanwhile, non-residential investment has also been pulling back. Notably, the government announced a significant scaling back in its capital spending plans earlier this year. Cumulative public capital investment by the year 2028 is slated to be more than \$30 billion lower.

Longer-term prospects for N&L's economy would brighten significantly should two major projects – a proposed offshore oilfield and a hydroelectricity deal with Quebec – ultimately get fast-tracked by the federal government and push ahead. There is reason to be optimistic as these projects would fall under the Eastern Energy Partnership.

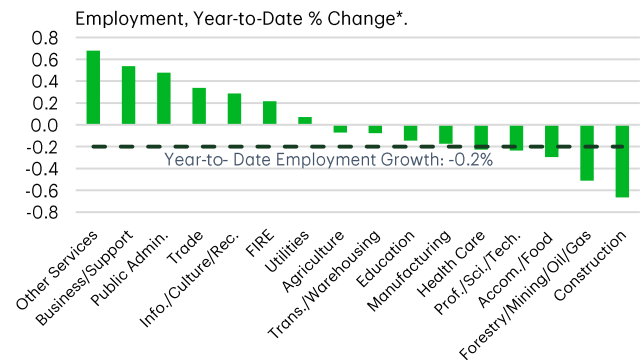
Chart 1: Newfoundland's Energy Sector Will Drive 2025 GDP Growth



*Projected.

Source: Canada-Newfoundland and Labrador Offshore Energy Regulator, TD Economics.

Chart 2: Employment Growth in N.L. Has Started to Cool



*Data as of November 2025. Source: Statistics Canada, TD Economics.

NFLD & Labrador Economic Forecasts

[Annual average % change, unless otherwise noted]

Economic Indicators	2025F	2026F	2027F
Real GDP	4.1	1.8	0.9
Nominal GDP	5.9	4.0	3.1
Employment	-0.2	-0.6	-0.1
Unemployment Rate (%)	10.3	10.9	11.1
Housing Starts (000's)	1.5	1.4	1.5
Existing Home Prices	7.8	3.7	3.0
Home Sales	7.6	1.7	4.5

Source: Statistics Canada, CMHC, CREA, Forecast by TD Economics.

Provincial Economic Forecasts

Provincial Economic Forecasts																		
Provinces	Real GDP (% Chg.)			Nominal GDP (% Chg.)			Employment (% Chg.)			Unemployment Rate (Average, %)			Housing Starts (Thousands)			Home Prices (% Chg.)		
	2025F	2026F	2027F	2025F	2026F	2027F	2025F	2026F	2027F	2025F	2026F	2027F	2025F	2026F	2027F	2025F	2026F	2027F
National	1.7	1.3	1.7	4.2	3.6	3.8	1.4	0.4	0.5	6.8	6.7	6.4	256.5	242.5	228.8	-0.8	4.1	4.4
Newfoundland & Labrador	4.1	1.8	0.9	5.9	4.0	3.1	-0.2	-0.6	-0.1	10.3	10.9	11.1	1.5	1.4	1.5	7.8	3.7	3.0
Prince Edward Island	2.2	1.5	1.6	4.3	3.9	3.6	0.8	0.4	0.6	8.1	8.1	8.0	1.7	1.5	1.3	2.9	5.1	3.5
Nova Scotia	1.6	1.6	1.2	4.1	4.0	3.2	0.5	-0.2	0.4	6.6	6.9	6.8	9.9	8.3	6.6	4.5	4.5	3.6
New Brunswick	1.6	1.3	1.1	3.9	3.5	3.1	1.2	0.4	0.4	7.2	7.6	7.4	7.1	6.9	4.5	5.9	4.9	4.2
Québec	1.3	1.1	1.6	4.3	3.4	3.6	1.7	-0.2	0.2	5.6	5.7	5.5	60.1	57.2	51.9	8.3	6.9	4.4
Ontario	1.5	1.0	1.8	4.0	3.4	3.8	1.0	0.1	0.5	7.6	7.5	7.0	62.1	60.7	64.1	-3.2	0.6	3.2
Manitoba	1.5	1.3	1.9	4.0	3.5	4.1	1.7	1.2	0.7	5.8	5.5	5.2	7.8	7.3	6.3	5.9	6.3	4.3
Saskatchewan	2.6	1.7	1.7	5.0	3.4	3.8	2.6	1.4	0.5	5.0	5.1	5.1	6.8	5.6	5.0	8.3	5.2	5.1
Alberta	2.5	1.9	2.1	4.3	3.8	4.0	2.8	1.8	0.8	7.3	6.9	6.3	56.8	52.2	43.0	3.7	4.4	4.3
British Columbia	1.8	1.5	1.7	4.3	4.0	3.8	1.2	0.4	0.7	6.2	6.1	5.6	42.7	41.4	44.7	-2.5	3.6	3.4

F: Forecast by TD Economics December 2025 Source: Canadian Real Estate Association, Canada Mortgage and Housing Corporation, Statistics Canada, TD Economics.

For any media enquiries please contact Oriana Kobelak at 416-982-8061

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Section 6: Rate application document

SASKPOWER 2026 AND 2027 RATE APPLICATION

Submitted: January 2, 2026

OUR COMPANY

Established in 1929, SaskPower is Saskatchewan's leading energy supplier. We are defined by our commitment to support economic growth and enhance the quality of life in our province. Our corporate mission: ensuring reliable and affordable power for our customers and the communities we serve.

SaskPower's team is made up of over 3,300 permanent full-time employees. We manage over \$15 billion in generation, transmission, distribution and other assets. Our company operates eight natural gas-fired power stations, three coal-fired power stations, seven hydroelectric stations, and two wind facilities. Combined, they generate 4,432 megawatts (MW) of electricity. SaskPower also buys power from various independent power producers. Our company's total available generation capacity is 6,125 MW.

We are responsible for serving over 560,000 customer accounts within Saskatchewan's geographic area of approximately 652,000 square kilometres. We maintain nearly 160,000 circuit kilometres of power lines, 65 high voltage switching stations and 191 distribution substations. Nearly four customer accounts are served per circuit kilometre.

Our company also has transmission interties at the Manitoba, Alberta and North Dakota borders.

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1.0 EXECUTIVE SUMMARY

SaskPower will play an integral role in delivering on the provincial government's vision for Saskatchewan to be at the centre of the North American electrical grid. *The Saskatchewan First Energy Security Strategy and Supply Plan* is a vision and long-term strategy for electricity in Saskatchewan that prioritizes energy security. For more information on the strategy, please see section 3.1.

Why is SaskPower applying for a rate increase and what is the impact on customers?

SaskPower is proposing flat rate increases of 3.9% effective February 1, 2026, and 3.9% effective February 1, 2027. The 3.9% increases would be applied to all customer classes. The February 1, 2026, rate increase will be implemented on an interim basis but is still subject to review through the public review process. The average residential customer will see bills increase by \$5/month on February 1, 2026, and \$5/month on February 1, 2027. The average farm customer will see increases of \$11/month on February 1, 2026, and \$11/month on February 1, 2027. The main drivers of the rate increase are increased capital investment, OM&A expense and fuel expense.

We're investing in our system reliability and supporting Saskatchewan's growth

SaskPower is committed to maintaining and upgrading the grid where necessary and expanding generation to ensure that we can meet Saskatchewan's electricity needs. Sustainment spending will increase by \$190 million from 2023-24 through 2026-27 to increase resilience and provide additional protection against unexpected disruptions or extreme weather events. In addition, it is essential that we expand the capabilities of our transmission system — both in province and through connections with other jurisdictions — to ensure reliable delivery of power to customers. For a list and description of major capital projects, please see section 7.3.

To meet increasing demand, SaskPower recently completed construction of the 370-MW Great Plains Power Station at the end of 2024, as well as expanded both the Yellowhead and Ermine Power Stations by 46 MW at each location in 2025. SaskPower is also constructing the 370-MW Aspen Power Station, has contracted 125 MW of flare gas generation, is replacing the Meadow Lake Generating Station with 55 MW of natural gas generation, and is adding 700 MW of wind and solar generation. SaskPower is also continuing its work on extending the life of up to 1,530 MW of existing coal-fired generation assets by 25 years, eliminating the significant capital investment needed to construct new natural gas generation facilities over the same horizon.

We're managing the pressure of rate increases

SaskPower last increased rates on September 1, 2022, and April 1, 2023, after approval of a two-year rate application. Prior to that, SaskPower did not increase rates for four consecutive fiscal years. We are mindful of the impact that rate increases have on our customers and consider them a last resort option. In a 2024 industry survey, SaskPower's rates were below the thermal average in every major consumption level category and in some cases, below the Canadian average, which includes the hydro generation jurisdictions. This rate application strikes a balance between minimizing rate increases and ensuring that the utility remains on solid financial footing.

2.0 THE BOTTOM LINE FOR CUSTOMERS

SaskPower is requesting system average rate increases of 3.9% effective February 1, 2026, and February 1, 2027.

2025-26 revenue impacts

3.9% flat rate increase effective February 1, 2026

Customer class	Base revenue (existing rates) (\$ millions)	2026 rate increase (%)	Additional revenue from 2026 increase (annualized) (\$ millions)	Monthly revenue increase (per customer)
Residential	\$ 645.4	3.9%	\$ 25.2	\$ 5
Farms	193.5	3.9%	7.5	11
Commercial	575.9	3.9%	22.5	29
Power Class	912.0	3.9%	35.6	26,703
Oilfields	476.4	3.9%	18.6	82
Reseller	100.0	3.9%	3.9	108,333
Total (System)	\$ 2,903.2	3.9%	\$ 113.2	\$ 17

Additional revenue from Feb 1, 2026, increase (prorated) (\$M)	\$ 18.9

* Due to the effective date of February 1, 2026, only 1/6, or approximately \$18.9M of the annualized revenue lift will be realized in 2025-26.

2026-27 revenue impacts

3.9% flat rate increase effective February 1, 2027

Customer class	Base revenue (existing rates) (\$ millions)	Additional revenue from 2026 increase (\$ millions)	2027 rate increase (%)	Additional revenue from 2027 increase (annualized) (\$ millions)	Monthly revenue increase (per customer)
Residential	\$ 643.6	\$ 25.1	3.9%	\$ 26.1	\$ 5
Farms	197.4	7.7	3.9%	8.0	11
Commercial	559.5	21.8	3.9%	22.7	29
Power Class	970.3	37.8	3.9%	39.3	29,519
Oilfields	496.1	19.3	3.9%	20.1	89
Reseller	103.7	4.0	3.9%	4.2	116,670
Total (System)	\$ 2,970.6	\$ 115.9	3.9%	\$ 120.4	\$ 18

Additional revenue from Feb 1, 2027, increase (prorated) (\$M)	\$ 20.1
Additional revenue from Feb 1, 2026, rate increase (\$M)	\$ 115.9
Total revenue due to rate increases in 2026-27 (\$M)	\$ 135.9

* Due to the effective date of February 1, 2027, only 1/6, or approximately \$20.1M of the annualized revenue lift will be realized in 2026-27.

** The ending revenue in 2025-26 does not equal the starting point in 2026-27 due to changes in the demand for electricity per class, number of customer accounts in the class and changes in usage per customer per class.

2.1 Helping customers deal with rate increases

Many SaskPower customers request greater support from the utility to reduce power usage and costs. Some customers have an interest in generating their own power and expect SaskPower to assist through various programs. SaskPower provides self generation and affordability programs, including energy efficiency education and tools, to help customers reduce their electricity use.

Online Energy Assessment for Homes: This online tool, available at saskpower.com, provides customers with energy-saving tips based on an evaluation of power and natural gas consumption. The tool considers a customer's lighting, heating, insulation and appliances, and estimates the power and natural gas used by the customer. Customers receive customized information about their consumption and tips for no-cost actions that could lead to savings.

Energy Assistance Program: This is a free program for low-income customers offering a home walkthrough, energy coaching and the installation of several energy-saving products, including LED lighting, low-flow water measures, a drying rack and a smart thermostat upgrade. Customers can save up to an estimated \$230 per year on their electricity, gas and water bills.

Northern First Nations Home Retrofit Program: SaskPower provides this program to customers in Northern First Nations communities who use electric heat as their primary heating source. Eligible customers will receive no-cost home retrofits, including upgraded insulation, insulating pipes, and installation of LED lights and upgraded windows and doors.

Northern Indigenous New Homes Program: As part of SaskPower's commitment to energy efficiency and affordability, the utility has launched the Indigenous New Homes Rebate. The program offers financial support to eligible Indigenous communities to help make new home builds more energy efficient during the construction phase. Many customers in northern communities rely on electric heat to heat their homes, which can cause high power bills. Homes constructed with the Indigenous New Homes Rebate could save between \$1,000-\$3,000 annually on their power bills based on the energy performance standards of the home constructed. The rebate is open to eligible Indigenous communities in Northern Saskatchewan who rely on electric heat as their primary heating source.

Energy Efficiency Discounts Program: SaskPower and SaskEnergy collaborate as Crowns in an annual partnership with local retailers to offer point of purchase discounts on a variety of energy efficient products including lighting controls, smart thermostats, select ENERGY STAR washing machines and dishwashers, low flow shower heads and aerators, bathroom ventilation fans and insulation measures.

Home Efficiency Retrofit Rebate Program: In partnership with SaskEnergy, this program offers rebates to eligible homeowners to enhance their homes' comfort and efficiency with high-performance windows, doors, insulation and air sealing retrofits. To be eligible for the rebates, homeowners must be registered under the "Canada Greener Homes" grant through Natural Resources Canada (NRCan). The program offers a maximum rebate of up to \$1,800. An additional \$200 is available to help cover the cost of pre- and post-upgrade EnerGuide evaluations.

Commercial Energy Optimization Program: This program assists commercial customers with affordability through free consulting services. This service identifies energy-saving opportunities, guides project development and identifies financial options through three services: The Energy Support Service (ESS) for small and medium business customers; the Energy Coach Services for large commercial businesses; and Custom Incentive Services. ESS identifies opportunities, develops business cases, reports and tracks energy management, and trains stakeholders. Energy Coach Services provides participants with all services in ESS, plus up to \$30,000 to hire or retain a dedicated energy champion who will identify, lead, develop and implement projects. Custom Incentive Services provides financial incentives to upgrade facilities with more energy-efficient equipment, thus improving affordability.

Commercial Space and Water Heater Rebate Program: SaskPower partners with SaskEnergy to offer rebates on high-efficiency equipment, including air conditioning roof-top units and electronically commutated motor pumps, to maximize energy cost savings.

Net Metering Program: This residential, farm and business program provides an opportunity for customers to generate their own electricity and deliver surplus energy to the grid. Participants must use an approved environmentally preferred technology with up to 100 kilowatts of nominal generating capacity. Customers are compensated at 7.5 cents per kilowatt hour for excess generation they deliver to the grid. A bi-directional meter keeps track of the electricity to and from the grid for billing purposes.

Residential Customer Engagement: This initiative features a variety of educational outreach efforts, including energy efficiency campaigns on social media, participation in trade shows, street fairs, and community events across the province. These activities create valuable opportunities to connect with customers in their own communities. Through accessible education and practical tools, the program empowers customers to make informed choices about energy use — helping them save both power and money.

3.0 WHAT HAS CHANGED SINCE THE LAST RATE APPLICATION?

3.1 Saskatchewan First Energy Security Strategy and Supply Plan

On October 20, 2025, the provincial government released the *Saskatchewan First Energy Security Strategy and Supply Plan*, establishing a provincial framework to ensure long-term electricity system reliability and affordability. Reliability and affordability are integrated as guiding principles throughout the plan. By leveraging existing assets and implementing a phased approach to new generation and infrastructure, the strategy mitigates rate volatility and ensures cost stability for customers. SaskPower's rate application reflects these priorities by aligning proposed capital investments with provincial objectives, demonstrating prudent financial planning, and supporting a secure and economically responsible electricity supply plan for Saskatchewan.

The strategy emphasizes maintaining secure baseload generation through the continued operation of existing coal facilities as a transitional measure, while advancing nuclear development, including small nuclear modular reactors, to meet future demand and decarbonization objectives. Complementary investments in transmission infrastructure are identified to enhance system resiliency and support interconnection opportunities.

Coal

SaskPower is well underway in executing a program to life extend its coal-fired generation facilities for 25 years. The scope of the Coal Fleet Repowering Initiative includes Boundary Dam Units 3-6; Shand; and Poplar River Units 1 and 2. The life extension of coal generating facilities is a key part of SaskPower's System Plan and the *Saskatchewan First Energy Security Strategy and Supply Plan*.

Along with the execution of detailed unit condition assessments, SaskPower is already advancing the initial phases of repowering on select units. Additionally, SaskPower is conducting a drilling and coring program to secure a long-term coal fuel supply.

Nuclear

To enable a future provincial electricity system powered by nuclear energy, SaskPower is undertaking planning and project development work required to deploy nuclear power starting in the mid to late 2030s. Nuclear power will support a reliable transition from coal and natural gas for baseload generation to achieve a carbon-neutral electricity sector by 2050.

Transmission

Transmission infrastructure is critical to energy security as we build out additional generation capacity and look to support economic growth throughout Saskatchewan. Intra-provincial transmission reinforcement will support safety and reliability goals and connect the southern and far north electricity grids. Meanwhile, expanding transmission capacity across our borders will

enhance the resilience of our provincial grid and provide flexibility when responding to unexpected disruptions or extreme weather events. As well, it will provide enhanced economic opportunities through additional exports of excess power.

3.2 Federal carbon tax rate rider

In 2023, the federal government approved Saskatchewan's request to transition management of the federal output-based pricing system (OBPS) from the federal government to the province, giving the province control and ensuring that the money collected stayed in Saskatchewan.

SaskPower recovered the cost of the OBPS payments through a federal carbon tax rate rider (rate rider) which was applied to customer bills. In 2024-25, through the Ministry of Environment, the provincial government provided a \$140 million Clean Electricity Transition Grant (CETG) to SaskPower for use towards in-year clean electricity operating and fuel-related costs.

In April 2025, the Government of Canada announced the elimination of the consumer-facing carbon tax, commonly known as the fuel charge, which applied to things such as gasoline, diesel, and natural gas. However, the federal government retained the requirement for an industrial OBPS that applies to larger emitters such as SaskPower.

Upon direction from the provincial government, SaskPower stopped the collection of the carbon tax rate rider on April 1, 2025. This resulted in the equivalent of a system-average 11.7% rate decrease for SaskPower ratepayers. However, SaskPower has continued to accrue the cost of its obligations under the OBPS, which is forecast to equal \$368 million in 2025-26. SaskPower anticipates that the province will provide approximately \$187 million of funding in 2025-26 to partially mitigate the lost revenue from the rate rider and support affordability for SaskPower customers. The corporation is also expecting to receive \$175 million in CETG payments from the province in 2025-26.

In the development of this rate application, it is assumed that starting in 2026-27, the OBPS will not apply to the corporation, no rate rider will be collected, and no CETG funding will be received. The elimination of the OBPS carbon charge and rate rider result in offsetting amounts. However, the loss of the CETG funding will create a financial shortfall for the corporation. To help SaskPower transition away from the CETG funding and minimize the rate increase request, SaskPower anticipates receiving \$175 million in grant funding from the province in 2026-27.

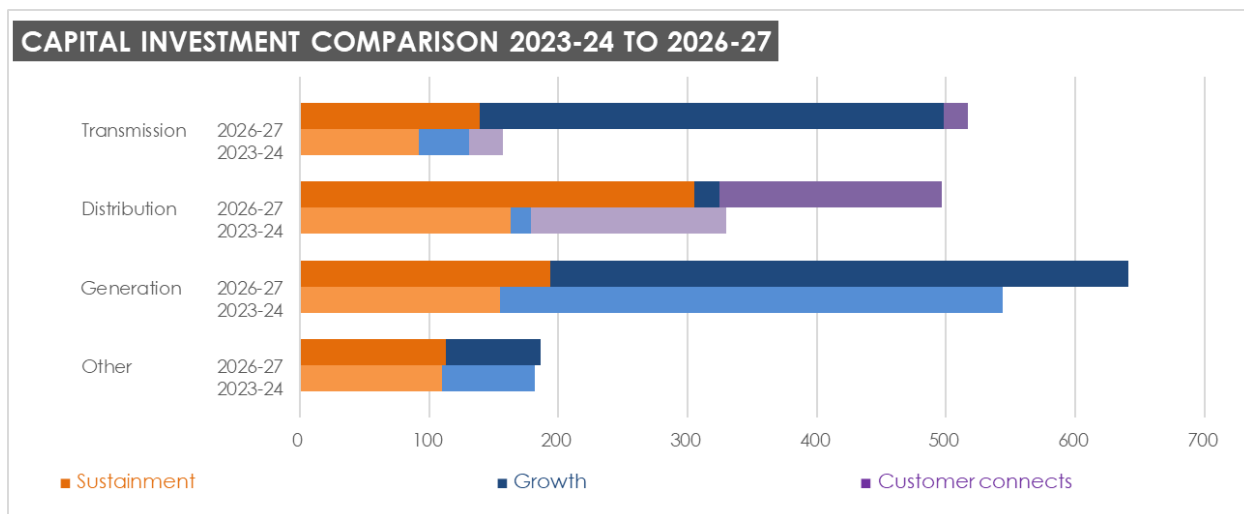
As negotiations between the Government of Saskatchewan and the federal government are ongoing, any changes to the OBPS that materially impact SaskPower's financial projections will be provided and explained in the mid-application update that will be filed later in the review process.

4.0 WHY DO WE NEED A RATE INCREASE?

Prior to launching a rate application, SaskPower considers the need for a reliable and affordable electricity system while also being mindful of the impact of rate increases on households, farms and businesses. In this rate application, the main drivers of the rate proposal are additional investment in transmission projects and other capital-related expenses. In addition, SaskPower is forecasting an increase in operating, maintenance, and administration (OM&A) expense, largely due to increased maintenance on our transmission and distribution systems and the generation fleet. New projects, corporate initiatives and general inflationary pressures also contribute to the increased OM&A expense. Increased demand for electricity, lower export revenues and increased fuel expense are also factors in this rate application. Without increasing rates, SaskPower is forecasting a net loss in 2026-27. The rate increases as proposed are forecasted to generate a modest net income in 2026-27 but SaskPower will fall short of its long-term return on equity (ROE) target of 8.5%.

4.1 Increased capital spending

Maintaining reliability standards requires investment in our infrastructure. Many assets are beyond their expected lives and require refurbishment or replacement. In addition, the demand for electricity in our province continues to increase and investment is required to support growth. From 2023-24 to 2026-27, SaskPower's annual capital spending increases from \$1.164 billion to \$1.692 billion, an increase of 45%.

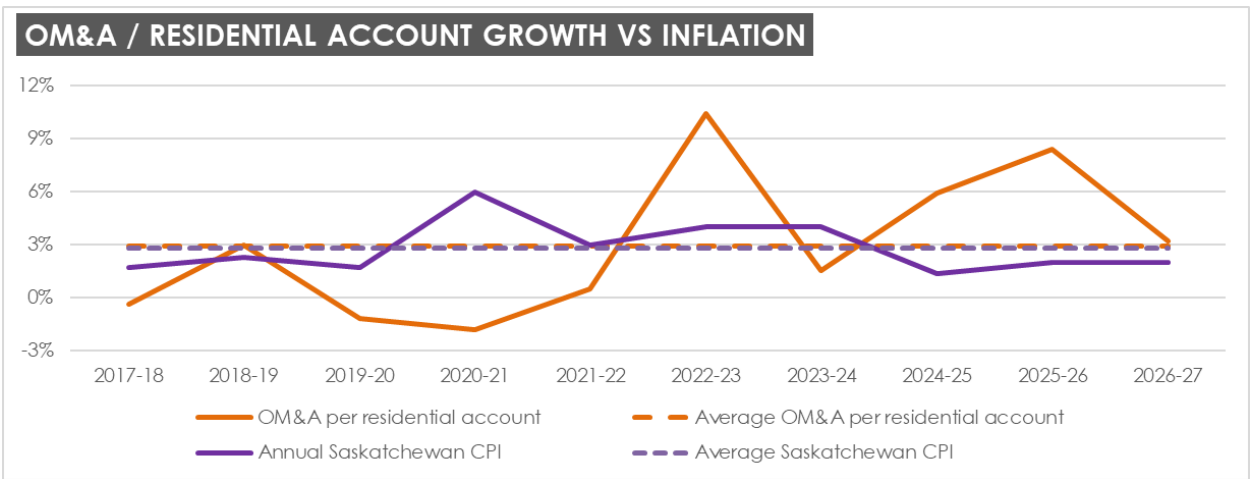


4.2 Increased operating, maintenance and administration (OM&A) expense

Since our last application, OM&A increased from \$811 million in 2023-24 to a forecast of \$987 million in 2026-27. This represents an increase of \$176 million, or 22%. The increase is the result of many factors, including increased costs related to growing demand and additional spending on

corporate priorities such as nuclear development, coal fleet repowering, increased maintenance activities and general inflationary pressures. In addition, from 2023-24 to 2026-27, SaskPower has seen increased expenses related to generation overhauls, additional transmission and distribution maintenance, additional resource requirements to operate the new Great Plains and Aspen Generation Stations, new resources to modernize and maintain SaskPower's distribution grid, and increased expenses due to the accounting treatment of information technology costs.

When measuring OM&A, the results can be quite volatile on a year-to-year basis. While costs for overhauls, emergency responses, and short-term projects can fluctuate significantly year to year, SaskPower's OM&A expenses per customer have remained consistent with inflation over time. To measure the OM&A efficiency, the Saskatchewan Rate Review Panel asked SaskPower to measure OM&A spending on a per residential account basis. The following chart shows that the average growth in OMA per residential account is consistent with the average growth in Saskatchewan CPI.

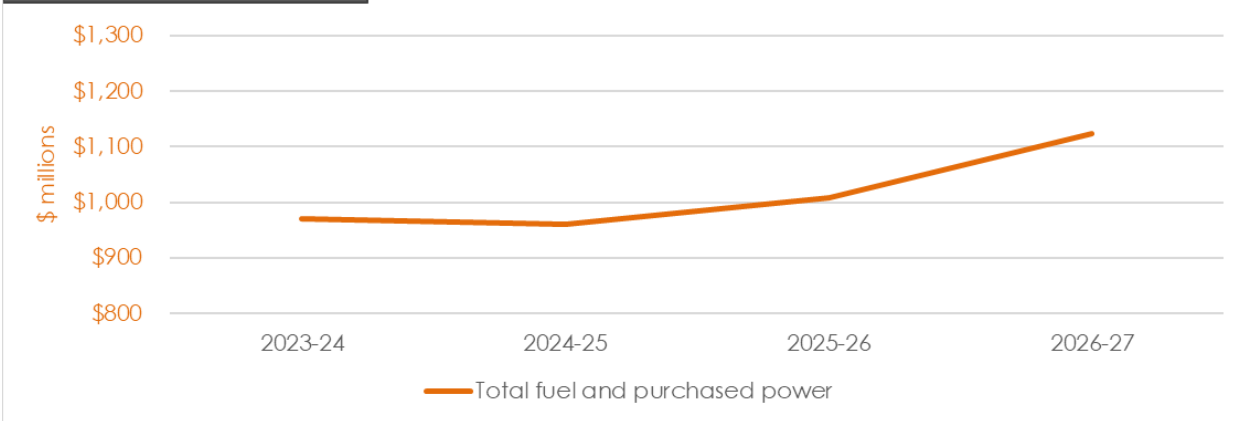


4.3 Increased fuel expense

This rate application assumes that SaskPower will not be subject to the OBPS or be eligible to receive the CETG from the Province effective April 1, 2026. As a result, the OBPS carbon charge and CETG funding are excluded from all fuel expense analysis.

SaskPower's fuel expense is expected to increase from \$971 million in 2023-24 to a forecast of \$1,124 million in 2026-27. This increase is driven by higher volumes and an increase in the average cost of generation, which is expected to grow from \$36.55 per MWh in 2023-24 to \$39.84 per MWh in 2026-27.

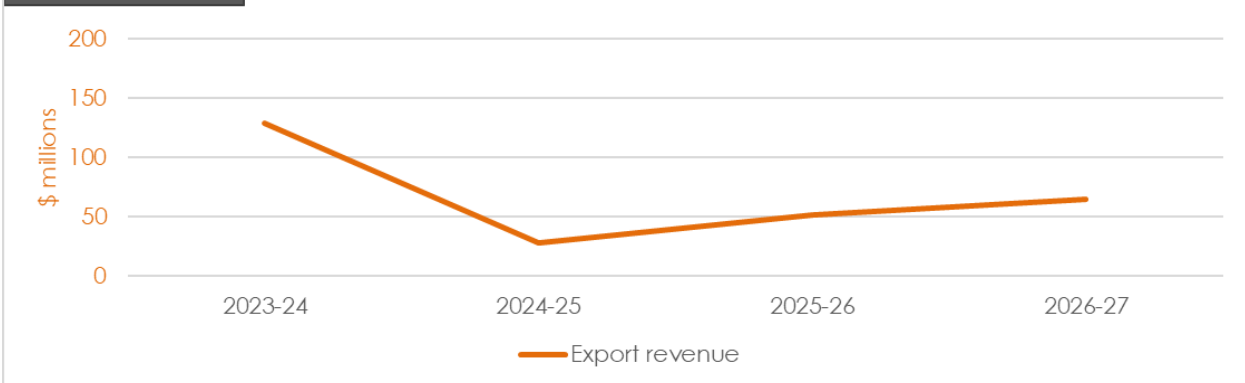
FUEL & PURCHASED POWER



4.4 Reduced exports

Revenue related to exporting electricity can be volatile as it is subject to the demand and market conditions of neighbouring jurisdictions. SaskPower pursues opportunities to sell electricity at a profit when available, especially to the Alberta and Southwest Power Pool (SPP) markets.

EXPORT REVENUE



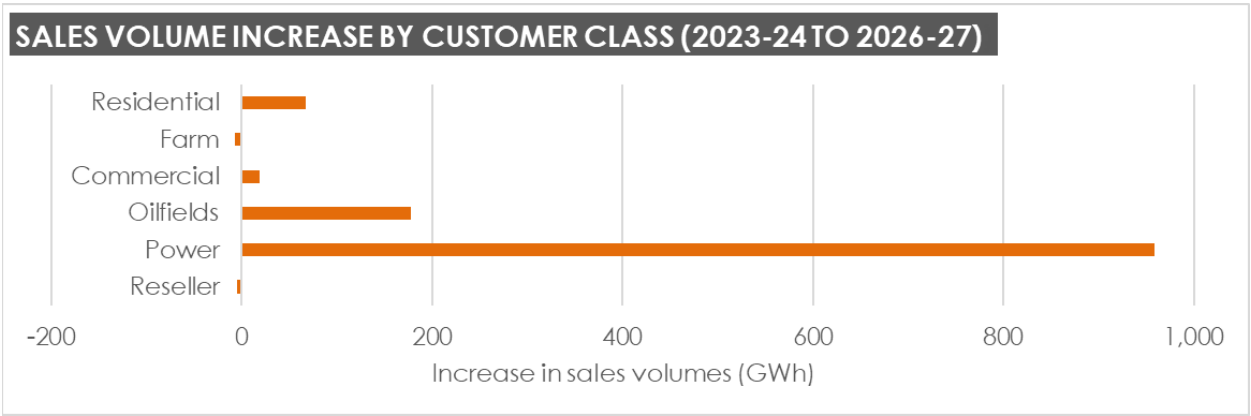
Export revenue peaked at \$139 million in 2022-23, largely due to increased export opportunities resulting from favourable market conditions in the Alberta market. Since then, Alberta added significant electricity generation capacity, reducing Alberta's need to import electricity. In 2024, Alberta became a net exporter of electricity for the first time since 2016. Reduced export opportunities because of unfavourable market conditions and an outage at a major intertie connection between Saskatchewan and Alberta resulted in only \$28 million in export revenue in 2024-25. SaskPower expects that the now-repaired intertie connection will help boost export revenue into Alberta but the increased generation in Alberta led to SaskPower forecasting relatively lower export prices and export revenue going forward compared to the prices and export revenue that were seen during the previous rate application filing.

Meanwhile, SaskPower is expanding its intertie capacity with the SPP from 150 MW to 650 MW to take advantage of import and export opportunities to the south. The SPP market is expected to see increased volatility due to the addition of large volumes of renewable generators, coupled with the retirement of dispatchable generation. The intermittency of renewable generation can

result in larger periods of low-priced hours when wind or solar is in ample supply, and extreme higher-priced hours when they are not. Although the pace of additional renewable generation and dispatchable generation retirements in the SPP is expected to slow, and the pace of dispatchable generation additions have increased, future market pricing will likely be heavily impacted by US data center growth.

4.5 Growth in electricity demand

SaskPower is forecasting the demand for electricity to increase to 25,489 GWh by 2026-27, an increase of 5.0% since 2023-24. Most of the increase is related to Power customer class sales, especially in the mining, pipeline and refinery sectors. Moderate increases are forecasted in Oilfield and Residential demand.



5.0 WHAT ARE WE DOING TO MINIMIZE RATE INCREASES?

5.1 No rate increase since April 2023

SaskPower last increased rates in 2022 and 2023. Prior to that, SaskPower increased rates in March of 2018. The interim rate increase on February 1, 2026, marks only the third rate increase in the previous eight fiscal years.

5.2 Efficiencies

SaskPower prioritizes efficiency, which has helped to reduce the need for rate increases in recent years. Since 2016-17, SaskPower's efficiency programs have resulted in accumulated savings of \$888 million as of the end of 2024-25. SaskPower also embedded a 1% efficiency target in each business unit's 2025-26 OM&A budget, resulting in a savings of \$9 million. SaskPower is on pace to achieve that target through managing position vacancies, re-prioritizing consultant budgets and reviewing information technology initiatives and software licence renewals. As part of an ongoing efficiency efforts, SaskPower is currently targeting another \$20 million of savings in 2026-27.

As a participant in the Government of Saskatchewan's collaboration initiative, SaskPower achieved nearly \$7.2 million in savings year to date largely through centralized line locating, a joint workforce management tool, and as a provincial project expeditor to facilitate investment in industrial projects in the province. Since 2013 (12 years of savings), SaskPower's collaboration contribution has totaled \$222 million representing 42% of the accumulated provincial collaboration savings.

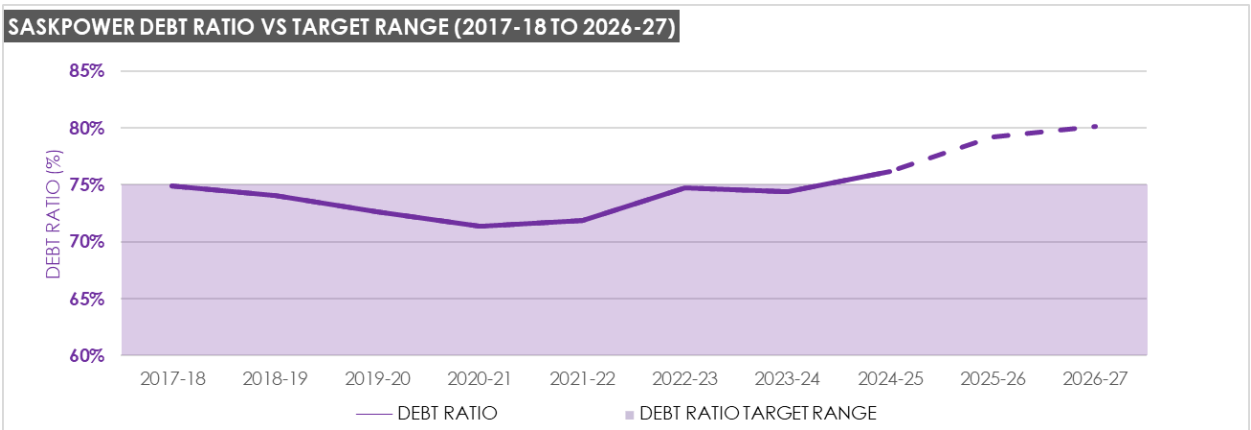
On the capital side, SaskPower reduced its initial 2025-26 capital budget by \$213 million. The Coal Fleet Repowering Initiative allowed several natural gas generation projects to be removed from our capital plan. For context, the Aspen Power Station, the most recent natural gas-fired combined cycle generating station built by SaskPower, has forecasted capital costs of \$1.7 billion.

Going forward, SaskPower will continue to focus on prioritization and efficiency while maximizing funding operations. New processes governing non-essential hirings and an internal organizational structure review focused on support functions will ensure that SaskPower is operating efficiently while meeting the company's needs in the future.

5.3 Per cent debt ratio will exceed the target range

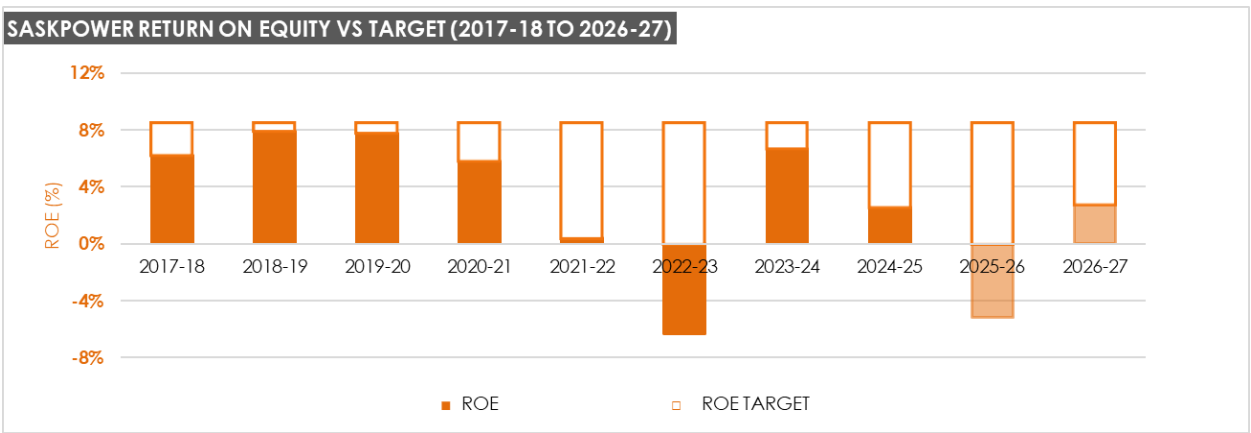
From 2024-25 to 2026-27, SaskPower's per cent debt ratio is forecasted to exceed SaskPower's target (between 60% to 75%), climbing to 80.1% in 2026-27. Affordability is a key priority at SaskPower, and this application seeks to find the right balance between keeping rates affordable while being mindful of the financial stability of the utility. The proposed rate increases in this rate application are not sufficient to prevent our per cent debt ratio from exceeding our

long-term debt ratio target. However, SaskPower's balance sheet remains adequately positioned to handle the financial pressures and increased capital spending requirements that will arise through the next decade.



5.4 Return on equity (ROE) will remain below target

SaskPower's long-term ROE target is 8.5%. SaskPower's application is forecasting the corporation falling short of its ROE target through the application period, only returning to a positive net income in 2026-27. SaskPower is prioritizing affordability over the need to earn its target ROE and has not achieved this target through the past decade.



5.5 Decreased dividend payment

In 2023-24, Crown Investments Corporation (CIC) reduced SaskPower's dividend rate from 30% to 10% of net income that is earned net of any grant funding. As SaskPower's earnings would be in a net loss position without grant funding, no dividend is expected to be paid through the application years.

5.6 External funding

SaskPower pursues external funding for projects and programs whenever possible, including funding made available through the provincial or federal governments. Depending on the program, funding is applied as offsets to either capital, OM&A or fuel. In 2026-27, SaskPower is forecasting external funding of almost \$190 million. Funding was made available for various programs and projects including:

- Rural Underground Distribution Mitigation Program
- Rural Rebuild and Improvement Program
- Southwest Power Pool to SaskPower Interconnection Project
- Small Modular Reactor Predevelopment
- Automated Metering Infrastructure Residential Mass Deployment
- Beatty to Wolverine 230 kV line
- Demand Side Management and Demand Response Programs

Further, in 2025-26, SaskPower will receive \$187 million through funding from the Government of Saskatchewan to help SaskPower meet its OBPS obligations after the provincial government directed SaskPower to remove the federal carbon tax rate rider. In addition, SaskPower is forecasting to receive \$175 million through the Clean Electricity Transition Grant (CETG) in 2025-26.

In 2026-27, it is assumed that the OBPS will not apply to the corporation, no rate rider will be collected, and no CETG funding will be received. The loss of the CETG funding will create a financial shortfall for the corporation. To maintain affordability for SaskPower's customers and minimize the rate increase request, SaskPower anticipates receiving \$175 million in grant funding from the Government of Saskatchewan in 2026-27.

6.0 COMPETITIVENESS

6.1 Rates – Canada

Electricity rates in Canada differ from jurisdiction to jurisdiction as each utility has unique characteristics that affect the cost to produce and deliver electricity. Some jurisdictions produce almost all their electricity through hydroelectric generation. The hydroelectric generation capacity in those jurisdictions generally results in cheaper electricity rates compared to the jurisdictions that rely mostly on thermal generation — coal, natural gas, oil or nuclear power.

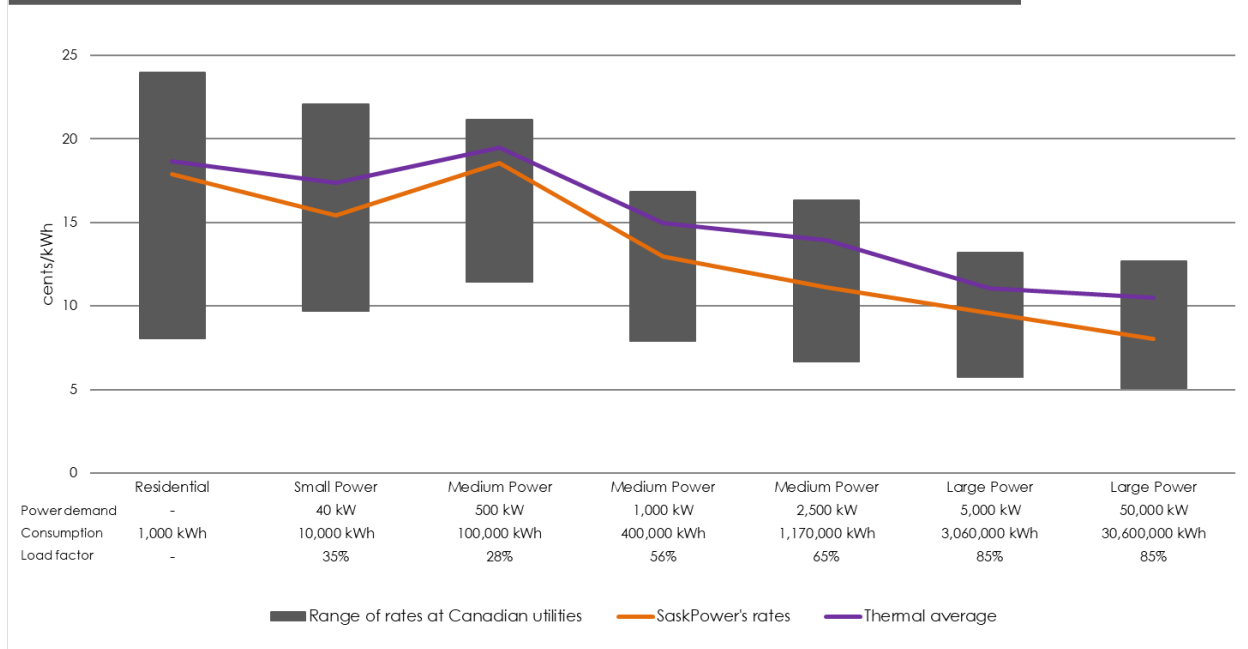
Market structures can also affect the price that customers pay for electricity. In many Canadian jurisdictions, utilities are vertically integrated — one utility provides the generation, transmission and distribution of electricity. In other jurisdictions, the market has been fully or partially deregulated which allows for multiple market participants to provide electricity services at varying pricing levels. Jurisdictions also offer a variety of rate options for customers so even customers with a similar consumption profile in the same jurisdiction can pay different rates for electricity.

The accounting treatment of certain costs can impact rates. For example, some utilities use deferral accounts to amortize a cost that would normally be expensed in one year under normal accounting standards but instead can be directed by a regulator to smooth the cost out over many years. Some utilities use rate riders to collect revenue for deferred costs in addition to the basic rate.

There are many other factors that positively or negatively impact the electricity rates from jurisdiction to jurisdiction. Differences in load growth, capacity factor, generation options, age of infrastructure, size of service area, customer density, financial health of the utility and environmental factors all contribute to the uniqueness of the rate being charged.

SaskPower's rates are considered competitive with other thermal jurisdictions. Every year, Hydro Québec publishes the *Comparison of Electricity Prices in Major North American Cities*. In the most recent report, which compares rates as of April 1, 2024, SaskPower's rates were below the thermal average in every major consumption category, and in some cases below the Canadian average, which includes the lower hydro generation jurisdictions.

SASKPOWER'S RATES WITHIN THE RANGE OF RATES OF OTHER CANADIAN UTILITIES AS ON APRIL 1, 2024

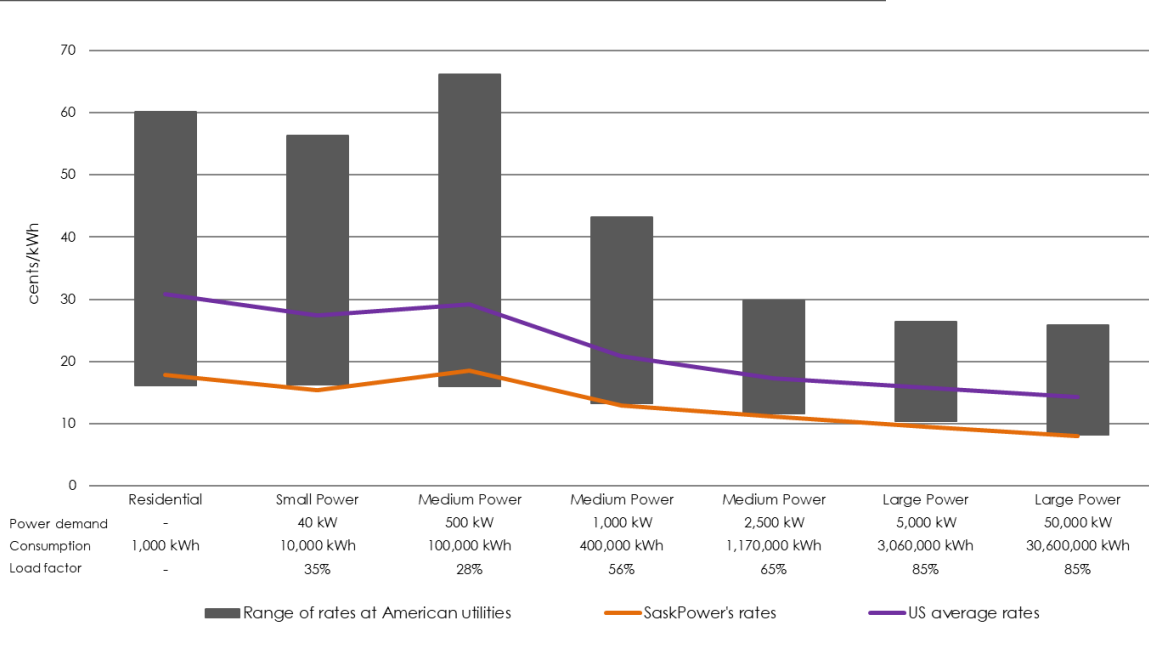


This comparison includes the basic charge, demand charge and energy charge, but not municipal charges or taxes.

6.2 Rates – United States

Ten major US cities are included in the Hydro-Québec electricity price survey: Boston, Chicago, Detroit, Houston, Miami, Nashville, New York, Portland, San Francisco and Seattle. SaskPower's rates compare favourably with the US cities listed in the survey. (The Hydro-Québec survey converted the US electricity rates to Canadian dollars as at noon, April 1, 2024: C\$1 = US\$0.7367.)

SASKPOWER'S RATES WITHIN THE RANGE OF RATES OF AMERICAN UTILITIES AS ON APRIL 1, 2024



This comparison includes the basic charge, demand charge and energy charge, but not municipal charges or taxes.

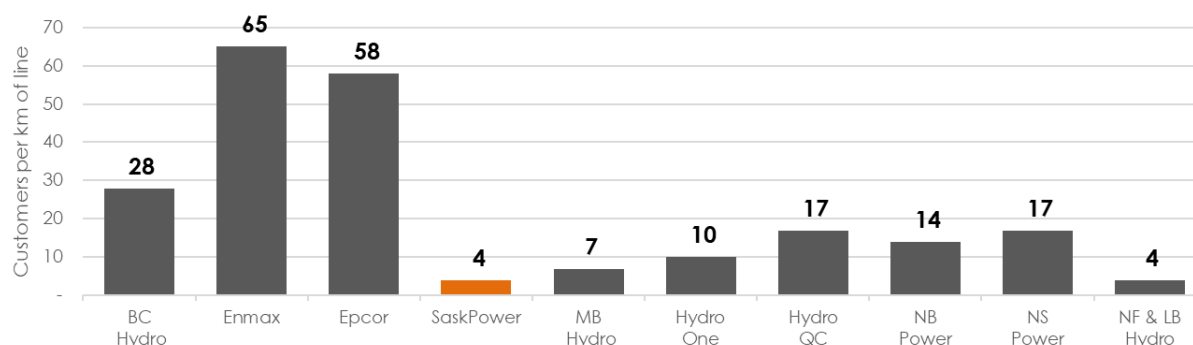
6.3 Jurisdictional comparisons

SaskPower serves customers across one of the largest service areas and distribution grids in the country. However, with a small population spread out across such a large service area, SaskPower also has one of the lowest customer densities in the country. The result is that the costs to deliver electricity across such a wide service area are shared by fewer customers, which negatively affects rate competitiveness for customer classes who operate at lower electricity consumption levels, such as residential and farm customers.

Other jurisdictions such as Québec, Manitoba and British Columbia can generate electricity at a lower cost thanks to almost exclusive use of low-cost legacy hydroelectric generation. Those provinces also have capacity to export significant amounts of electricity to other jurisdictions with the additional export revenue subsidizing their own electricity rates, keeping their rates even lower. While legacy hydro generation is very cost-effective, new hydroelectric generation is considerably more expensive.

SaskPower has limited hydroelectric generation availability and must rely on a variety of generation options, including coal, natural gas, hydro, wind and solar. This generation diversity helps protect SaskPower and its ratepayers from the impact of negative events such as droughts or high input prices for a particular generation type.

CUSTOMER ACCOUNTS PER KM OF DISTRIBUTION AND TRANSMISSION LINES



At nearly four customer accounts per circuit kilometre, SaskPower serves an extremely large service area and operates one of the most extensive networks of transmission and distribution lines of any Canadian utility.

Customer experience

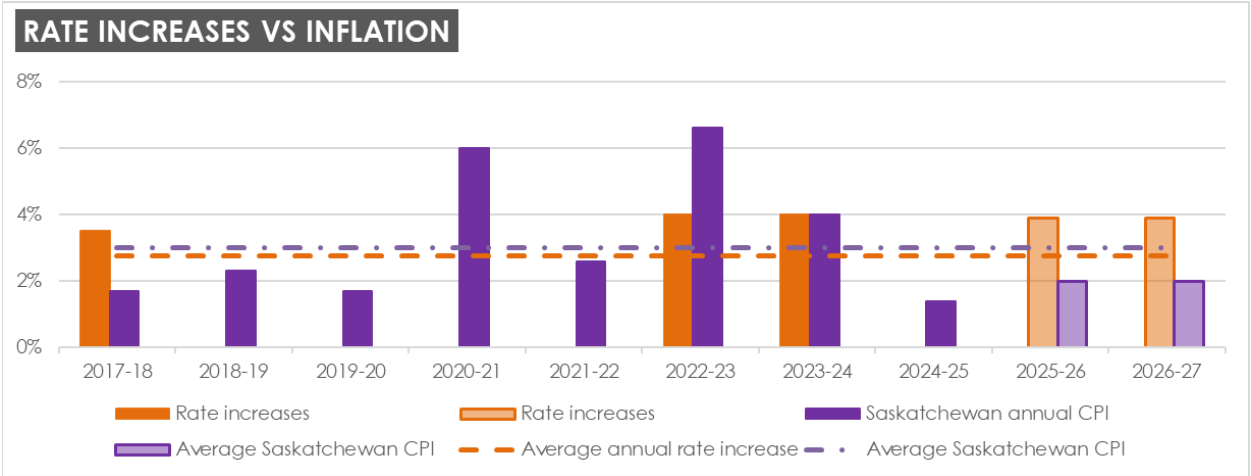
SaskPower's Customer Experience Index measures customer perceptions on how well SaskPower delivers the experiences that are most likely to create and sustain loyalty. The results are based on annual customer experience surveys for all three of our customer segments: residential customers, small & medium business customers, and key & major account customers. Customer experience is a key component of customer advocacy, social licence, and brand trust.

The most recent results from 2025-26 were as follows: 69% for residential customers; 70% for small & medium business customers; and 86% for key & major account customers. The residential customer results achieved its target, whereas small & medium business customer results were slightly below our target, and the key & major account customer results exceeded target. Both residential and small & medium business customer segments reported improvements in feeling valued as a customer and also reported feeling the financial pressures of inflation. Customers in those segments are looking to SaskPower for information and affordability programs to lower their electricity use and costs. Key & major account customers reported positive perceptions about SaskPower being a trusted advisor and improvements in customer advocacy. Reliable power is an expectation of all three customer segments.

Electricity Canada provides survey data related to national electricity customer satisfaction for residential customers. SaskPower continues to lead the regional and national averages. The most recent survey indicates that 78% of SaskPower's residential customers are very satisfied or somewhat satisfied with SaskPower compared to a national average of 69%. SaskPower exceeded the national average for the 17th year in a row.

6.4 Rate increase history

SaskPower has increased rates sporadically over the past decade, including a period of four consecutive fiscal years without a rate increase from 2018-19 through 2021-22. Overall, SaskPower increased rates in five of the past 10 years. Over the ten-year period from 2017-18 through the application years, SaskPower's rate increase average is slightly below the average rate of inflation in the province.



7.0 SASKPOWER'S FINANCIAL REQUIREMENTS

SaskPower determines its revenue requirements based on the principle that SaskPower must set rates that will collect sufficient revenue to recover all reasonable costs and to provide a return to the shareholder. SaskPower's long-term return on equity target is 8.5%.

Through the next section, SaskPower provides the following financial information: the two most recent fiscal years, followed by the current year's forecast (2025-26) and business plan forecast for 2026-27. The 2025-26 and 2026-27 forecasts assume that the rate application is approved as requested. Please note that forecasts represent a best estimate at a point in time and are subject to change.

Financial summary

CONSOLIDATED STATEMENT OF INCOME

	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
(in millions)				
REVENUE				
Saskatchewan electricity sales	\$ 2,856	\$ 2,842	\$ 2,922	\$ 3,107
Federal carbon charge rate rider	240	268	-	-
Government of Saskatchewan funding	-	-	187	175
Exports	129	28	52	65
Other revenue	154	116	132	179
	3,379	3,254	3,293	3,526
EXPENSE				
Fuel and purchased power	971	961	1,009	1,124
Clean Electricity Transition Grant	-	(140)	(175)	-
OBPS carbon charge	269	280	368	-
Operating, maintenance & administration	811	869	947	987
Depreciation	605	638	675	712
Finance charges	409	418	463	458
Taxes	92	100	105	113
Other expenses	38	52	48	53
	3,195	3,178	3,440	3,447
NET INCOME (LOSS)	\$ 184	\$ 76	\$ (147)	\$ 79
RETURN ON EQUITY	6.7%	2.6%	(5.2%)	2.8%

* The Clean Electricity Transition Grant was used to offset Fuel and Purchased Power (F&PP) and certain OM&A expenses. Of the \$140 million received in 2024-25, \$136 million was applied to F&PP and \$4 million to OM&A. Of the \$175 million received in 2025-26, \$161 million was applied to F&PP and \$14 million to OM&A.

Revenue is forecasted to increase by \$147 million from 2023-24 to 2026-27. SaskPower is anticipating higher domestic electricity sales revenue, due to both increased sales volumes and through rate increases, offset by lower export revenue.

Meanwhile, expenses will also increase over the same period by \$252 million. Capital-related expenses represent the largest increase, followed by OM&A and fuel expense.

7.1 Revenue

The following table shows SaskPower's revenue forecast, including the financial impact of the proposed rate increases:

REVENUE				
	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
<i>(in millions)</i>				
Saskatchewan electricity sales	\$ 2,856	\$ 2,842	\$ 2,922	\$ 3,107
Federal carbon charge rate rider	240	268	-	-
Government of Saskatchewan funding	-	-	187	175
Exports	129	28	52	65
Other revenue	154	116	132	179
TOTAL REVENUE	\$ 3,379	\$ 3,254	\$ 3,293	\$ 3,526

7.1.1 Saskatchewan electricity sales

Saskatchewan electricity sales represent the sale of electricity to all customer classes within the province. Sales can fluctuate due to economic conditions, weather, number of customers and electricity rates, and are driven by customer demand. Other than a decrease from 2023-24 to 2024-25, sales volumes increase every year, peaking at 25,489 GWh in 2026-27.

SASKATCHEWAN SALES

	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
(in millions)				
SASKATCHEWAN SALES				
Residential	\$ 632	\$ 637	\$ 645	\$ 644
Farm	198	188	194	197
Commercial	557	557	576	560
Oilfield	469	477	476	496
Power	895	879	912	970
Reseller	105	104	100	104
	2,856	2,842	2,903	2,971
Revenue lift due to rate increase			19	136
	2,856	2,842	2,922	3,107
Federal carbon charge rate rider	240	268	-	-
Government of Saskatchewan funding	-	-	187	175
SASKATCHEWAN ELECTRICITY SALES	\$ 3,096	\$ 3,110	\$ 3,109	\$ 3,282

SASKATCHEWAN SALES VOLUME

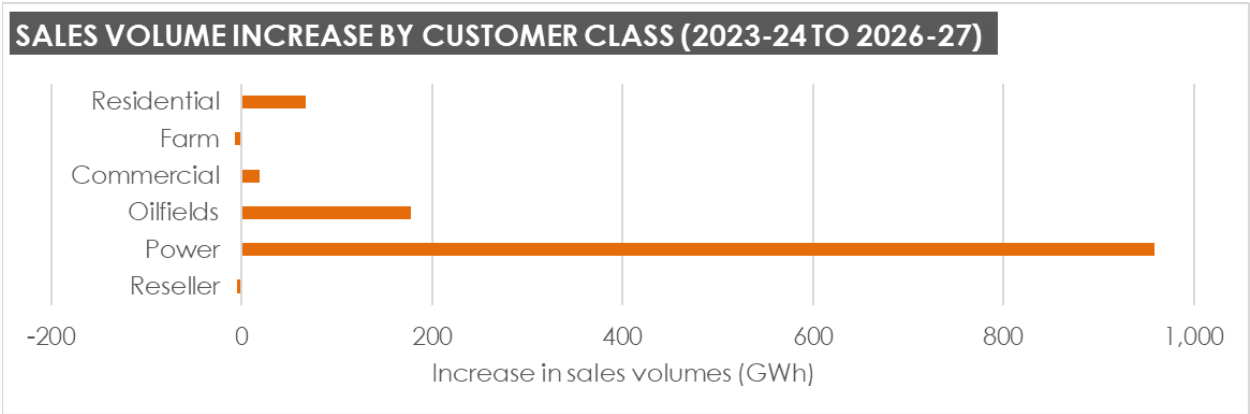
	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
(in GWh)				
SASKATCHEWAN SALES				
Residential	3,224	3,248	3,299	3,291
Farm	1,305	1,226	1,275	1,298
Commercial	3,749	3,744	3,886	3,768
Oilfields	4,320	4,395	4,361	4,498
Power	10,531	10,228	10,624	11,489
Reseller	1,150	1,143	1,106	1,145
TOTAL SASKATCHEWAN SALES	24,279	23,984	24,551	25,489

Our load forecast drives our supply planning and budgeting processes. SaskPower creates the load forecast based on many inputs, including historical information, weather data, economic drivers and forecasts provided by industrial customers.

SaskPower's load forecasting methodology is subject to a review every five years to ensure the methodology is appropriate and consistent with industry standards. The consultancy firm iTron reviewed SaskPower's forecast methodology in 2023-24. iTron was largely in agreement with the

existing methodology but did identify some areas for improvement. SaskPower has incorporated all recommendations into the current load forecast.

SaskPower is forecasting steady growth in Saskatchewan sales volumes through the application period, for a total of 5% load growth from 2023-24 to 2026-27. Growth is expected in all customer classes other than the Reseller and Farm classes, with Power class customers responsible for most of the increase. Moderate increases in the Oilfield and Residential classes also contribute to growth in demand.



The Power class is forecasting increased demand for power in many industries, including mining, pipelines and refineries.

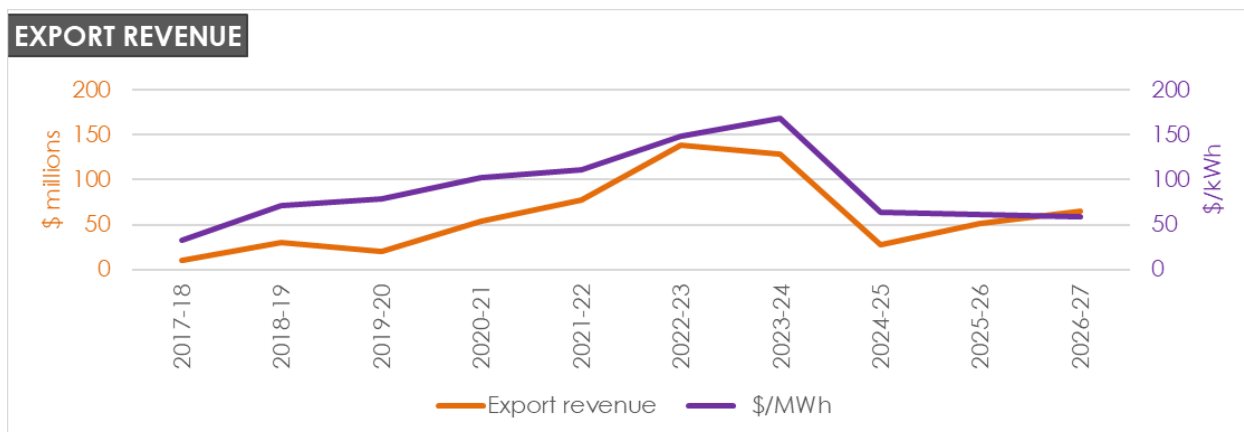
7.1.2 Exports

Once SaskPower has met electricity load requirements in Saskatchewan, the company looks for profitable opportunities to sell surplus electricity into neighbouring jurisdictions. Export opportunities are largely dependent on market conditions in those jurisdictions. As such, export revenue can be volatile and difficult to forecast as many of the factors that impact export revenue are outside of SaskPower’s control.

SaskPower exports are primarily made to Alberta and the Southwest Power Pool over transmission interconnections. Export revenue and pricing are not subject to the rate review process.

EXPORTS				
	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
EXPORTS	\$ 129	\$ 28	\$ 52	\$ 65

SaskPower’s export revenue is forecasting to decline in 2026-27 compared to 2023-24. During peak revenue years, most of SaskPower’s export revenue was earned through exports to Alberta. Since then, electricity capacity in Alberta has increased and lower export prices are expected going forward.



7.1.3 Other revenue

Other revenue includes various non-electricity products and services such as customer contributions, carbon dioxide (CO₂) sales, and other non-energy related charges.

OTHER REVENUE				
(in millions)	ACTUAL		ACTUAL	
	2023-24	2024-25	2025-26	BUSINESS PLAN 2026-27
CO ₂ sales	\$ 26	\$ 19	\$ 17	\$ 18
Customer contributions	90	58	80	124
Miscellaneous revenue	38	39	35	37
TOTAL OTHER REVENUE	\$ 154	\$ 116	\$ 132	\$ 179

Other revenue was \$154 million in 2023-24. SaskPower is forecasting volatility in customer contributions, and as a result, other revenue will fluctuate through the application period before settling at \$179 million in 2026-27.

7.2 Expenses

The following table presents SaskPower's operating costs by major category:

EXPENSES				
(in millions)	ACTUAL	ACTUAL	FORECAST	BUSINESS
	2023-24	2024-25	2025-26	PLAN
EXPENSES				
Fuel and purchased power	\$ 971	\$ 961	\$ 1,009	\$ 1,124
Clean Electricity Transition Grant	-	(140)	(175)	-
OBPS carbon charge	269	280	368	-
Operating, maintenance & administration	811	869	947	987
Depreciation	605	638	675	712
Finance charges	409	418	463	458
Taxes	92	100	105	113
Other	38	52	48	53
TOTAL EXPENSES	\$ 3,195	\$ 3,178	\$ 3,440	\$ 3,447

7.2.1 Fuel and purchased power (F&PP)

Costs categorized as F&PP include the fuel charges related to electricity generated at SaskPower-owned facilities, the cost of energy purchased from Independent Power Producers (IPPs), and the cost to import electricity from neighbouring jurisdictions.

SaskPower and its IPPs use a variety of sources to generate electricity. The dispatch of generation is primarily focused on cost. Cheaper generation is prioritized over more expensive generation whenever possible. The lowest-cost generation source is dispatched first, followed by the next lowest-cost generation source and so on until demand is met. SaskPower will also pursue export opportunities if market prices in other jurisdictions will allow SaskPower to profit.

Input costs, availability and demand fluctuations can all affect the cost of F&PP. Careful planning is required to ensure that the generation fleet is being used effectively and efficiently. Some generation sources, such as wind and solar power, are intermittent and SaskPower must take the generation when it is available. Hydro generation is very important from a cost perspective. While hydro is very low-cost, the availability of hydro generation can be volatile due to its reliance on precipitation levels. Opportunities to import electricity at a cheaper cost are always being monitored as well.

Finally, generation unit maintenance must be considered. Maintenance is scheduled outside of forecasted peak demand periods (summer and winter) to ensure that SaskPower has sufficient capacity when needed most. Generally, maintenance is pushed to the spring or fall whenever possible.

FUEL AND PURCHASED POWER

	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
(in millions)				
FUEL AND PURCHASED POWER				
Gas	\$ 366	\$ 316	\$ 339	\$ 398
Coal	296	313	311	353
Imports	178	173	169	176
Wind	84	108	125	124
Hydro	16	18	18	24
Solar	6	8	11	13
Other	25	25	36	36
TOTAL FUEL AND PURCHASED POWER	\$ 971	\$ 961	\$ 1,009	\$ 1,124

FUEL AND PURCHASED POWER VOLUME

	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
(in GWh)				
FUEL AND PURCHASED POWER				
Gas	11,934	12,426	13,054	11,714
Coal	7,895	6,245	6,244	7,813
Imports	2,027	1,929	1,866	1,953
Wind	1,981	2,531	2,856	2,913
Hydro	2,490	2,769	2,727	3,582
Solar	71	94	125	146
Other	177	180	188	251
FUEL AND PURCHASED POWER VOLUME	26,575	26,174	27,060	28,372

F&PP is forecasted to increase by \$153 million from 2023-24 to 2026-27, due to increased costs among almost all fuel types. Overall, the cost of generation is forecast to increase from \$36.55 per MWh in 2023-24 to \$39.84 per MWh in 2026-27.

In terms of volumes, SaskPower is forecasting an increase of 1,797 GWh from 2023-24 to 2026-27 to accommodate increased demand. In contrast, coal volumes are forecasted to decrease by 82 GWh from 2023-24 to 2026-27. However, work is underway over the next decade to repower SaskPower's coal fleet to provide baseload electricity. Natural gas generation will decrease by 220 GWh over the same period, while imports will decrease by 74 GWh. The increased demand will be met through higher volumes in other fuel sources such as hydro, wind and solar generation.

7.2.2 Operating, maintenance & administration (OM&A)

OM&A expense includes the costs to operate our facilities on a day-to-day basis. People costs, such as salaries, benefits, consultants and contractors, and maintenance costs, such as generation overhauls, facilities maintenance and vegetation management, form the majority of the costs in this expense category.

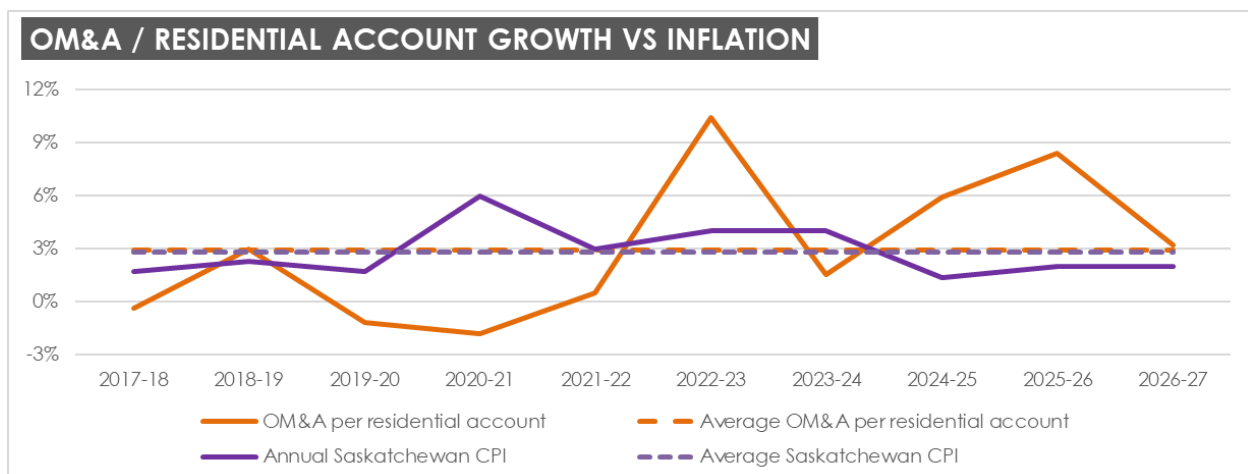
OPERATING, MAINTENANCE AND ADMINISTRATION

(in millions)	ACTUAL	ACTUAL	FORECAST	BUSINESS PLAN
	2023-24	2024-25	2025-26	2026-27
TOTAL OM&A	\$ 811	\$ 869	\$ 947	\$ 987

SaskPower is forecasting OM&A to increase from \$811 million in 2023-24 to \$987 million by 2026-27, an increase of 22%. A few factors contributed to the increase in OM&A, including:

- Increased generation overhaul expenses;
- Additional transmission and distribution maintenance costs;
- Increased resources to run SaskPower's nuclear small modular reactor development program;
- New resources to plan and execute on the Coal Fleet Repowering Initiative;
- Additional costs to staff and operate the new Great Plains and Aspen Generation Stations;
- New resources to modernize and maintain SaskPower's distribution grid; and
- Changes in the accounting treatment of information technology costs.

The Saskatchewan Rate Review Panel asked SaskPower to measure OM&A growth as a percentage of residential account growth and compare that result to inflation. Some significant OM&A costs, such as overhauls, can fluctuate significantly from year to year. To more accurately show the trend of OM&A per residential account compared to inflation, the following chart shows a 10-year period including the two application years.



Since 2017-18 (including the two years affected by the rate increase proposal), SaskPower's OM&A per residential account is slightly above the inflation rate over the same period.

7.2.3 Capital-related expenses

SaskPower classifies depreciation, finance charges, taxes and other expenses as capital-related expenses, as they are primarily driven by capital spending. Depreciation expense is based on the costs and related useful lives of assets as they go into service. Finance charges reflect the borrowing costs of the corporation. Tax expense is driven by capital spending as the largest component of tax expense is the corporation capital tax. Other expenses include environmental and decommissioning expenses related to our assets, as well as gains and losses on the disposal of assets. Capital investment is expected to increase over the application period, from \$1,164 million in 2023-24 to \$1,692 million through 2026-27. In total, from 2023-24 through 2026-27, SaskPower will spend over \$6 billion in capital investment, driving the increase in capital-related expense growth.

7.2.3.1 Depreciation & amortization

Depreciation represents a charge to income and is based on SaskPower's capital expenditures. Assets are amortized to income on a straight-line basis over the estimated life cycle of the asset group. Depreciation rates are established based on depreciation studies and are reviewed internally every year. SaskPower's depreciation rates are independently reviewed approximately every five years. The last external review was done by Concentric Advisors in 2023. The consultant did not recommend any major changes.

DEPRECIATION AND AMORTIZATION

(in millions)	ACTUAL		ACTUAL FORECAST		BUSINESS PLAN
	2023-24	2024-25	2025-26	2026-27	
DEPRECIATION AND AMORTIZATION					
Depreciation	\$ 554	\$ 587	\$ 624	\$ 661	
Amortization of right-of-use assets	51	51	51	51	
TOTAL DEPRECIATION AND AMORTIZATION	\$ 605	\$ 638	\$ 675	\$ 712	

Depreciation expense is driven by capital spending. As assets are brought into service, depreciation expense increases. Conversely, as assets are fully depreciated, their costs are removed from depreciation expense. Depreciation expense increases from \$605 million in 2023-24 to \$712 million in 2026-27 due to increased capital spending.

7.2.3.2 Finance charges

Finance charges include the net amount of interest on SaskPower's long- and short-term borrowings and lease liabilities, offset by interest capitalized and debt retirement fund earnings.

FINANCE CHARGES				
(in millions)	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
FINANCE CHARGES				
Interest on borrowings	\$ 448	\$ 484	\$ 518	\$ 551
Interest capitalized	(39)	(47)	(48)	(70)
Debt retirement fund earnings	(14)	(32)	(31)	(42)
Other interest and charges	14	13	24	19
TOTAL FINANCE CHARGES	\$ 409	\$ 418	\$ 463	\$ 458

SaskPower's finance expense will increase from 2023-24 to 2026-27, largely due to SaskPower's plan to increase capital spending, resulting in additional borrowings. From 2023-24 to 2026-27, the interest on borrowings is expected to increase by \$103 million.

Interest expense on assets under construction can be capitalized and will be depreciated along with the asset when the asset goes into service. Interest capitalized is an offset to finance charges. From 2023-24 to 2026-27, interest capitalized is forecasted to increase by \$31 million, creating a larger offset against finance charges.

SaskPower contributes at least 1% of the face value of certain outstanding debts annually to debt retirement funds. The funds are administered by the Government of Saskatchewan, and the funds are used to settle debts at maturity. The interest earned on those funds represent debt retirement fund earnings and are an offset to finance expense. SaskPower is forecasting that debt retirement fund earnings will increase from \$14 million in 2023-24 to \$42 million in 2026-27, due in part to an increase in total borrowings, creating a larger offset to finance charges in 2026-27.

7.2.3.3 Taxes

Taxes represent the payment of corporate capital tax and grants-in-lieu of taxes. Corporate capital tax is based on SaskPower's capital structure and increases as the size of our company grows. Steady increases in capital taxes are expected as a result of SaskPower's capital program. Meanwhile, grants-in-lieu are based on electricity revenues and are expected to increase modestly over the review period.

TAXES				
(in millions)	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
TAXES				
Corporate capital tax	\$ 57	\$ 64	\$ 70	\$ 76
Grants in lieu	34	35	34	36
Other	1	1	1	1
TOTAL TAXES	\$ 92	\$ 100	\$ 105	\$ 113

Taxes increased from \$92 million in 2023-24 to \$113 million by 2026-27. SaskPower's increased capital spending will result in higher corporate capital taxes.

7.2.3.4 Other expenses

The other expenses category includes gains or losses on asset disposals and retirements that were previously classified as part of depreciation expense. It also includes environmental and decommissioning expenses related to the operation of our assets. These expenses are expected to fluctuate through the review period.

OTHER EXPENSES				
(in millions)	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
OTHER EXPENSES	\$ 38	\$ 52	\$ 48	\$ 53

Other expenses are forecasted to increase from \$38 million in 2023-24 to \$53 million in 2026-27.

7.3 Capital

SaskPower's annual capital spending is expected to increase significantly through the review period. From 2023-24 to 2026-27, Capital spending is forecasted to increase from \$1,164 million to \$1,692 million, an increase of 45%.

CAPITAL SPENDING				
(in millions)	ACTUAL 2023-24	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
CAPITAL SUSTAINMENT INVESTMENT				
Generation	\$ 155	\$ 182	\$ 224	\$ 155
Transmission	92	90	140	139
Distribution	163	177	219	304
Other	110	106	105	112
TOTAL SUSTAINMENT INVESTMENT	520	555	688	710
GROWTH & COMPLIANCE INVESTMENT				
Generation	389	590	728	487
Transmission	39	51	150	359
Distribution	16	22	17	20
Customer Connects	177	192	242	191
TOTAL GROWTH & COMPLIANCE INVESTMENT	621	855	1,137	1,057
TOTAL STRATEGIC & OTHER INVESTMENT	72	87	114	73
Future Electricity Fund	(44)	(72)	(149)	(128)
Other Funding	(5)	(2)	(3)	(20)
TOTAL CAPITAL SPENDING	\$ 1,164	\$ 1,423	\$ 1,787	\$ 1,692

Sustainment spending is forecasted to increase from \$520 million in 2023-24 to \$710 million by 2026-27, largely for transmission and distribution projects. Many capital sustainment projects are underway to address SaskPower's aging infrastructure as significant sections of our grid are nearing or beyond their expected useful lives. Some of the projects that account for the increase in sustainment spending include the Rural Underground Mitigation Program, Rural Rebuild & Improvement Program, and pole replacement programs throughout the province.

Growth and compliance investments represent new construction to accommodate growth either through generation capacity additions or transmission and distribution additions to increase line capacity, reinforce the grid and to expand SaskPower's interconnections with neighbouring jurisdictions.

SaskPower has pursued funding opportunities wherever possible. In 2025-26 and 2026-27, SaskPower will receive funding of \$152 million and \$148 million respectively to offset capital expenditures. Below is a summary of some major capital projects that either are already underway or where construction will start during the application years.

Major capital projects

Generation

- **Aspen Power Station** - The scope of this project is to construct a 370-megawatt (MW) combined cycle natural gas power station. It is required to support SaskPower's increasing load growth and meet the requirements of the supply plan.
- **Ermine Unit #3 and Yellowhead Unit #4** - The scope of this project is to install one new 46-MW simple cycle unit at Ermine Power Station and one new 46-MW simple cycle unit at Yellowhead Power Station in order to support SaskPower's increasing load growth and meet the requirements of the supply plan.
- **Poplar River Power Station (PRPS) Ash Lagoon Capacity Improvement** - The scope of this project is to increase PRPS ash lagoon capacity to extend operations. This will be achieved by removing 1.2 million cubic meters of ash from cell 5, increasing the length of discharge pipes in cell 5 and improving the flow control structure and culverts from cell 4 West to 3 North.
- **Independent Power Producers and Other Generation** – SaskPower is contracting 125 MW of flare gas generation and replacing Meadow Lake Generating Station with 55 MW of natural gas generation. In addition, up to 700 MW of wind and solar generation will be added through various projects, including the Rose Valley Wind Energy Project and Seven Stars Wind Energy Project, each providing 200 MW of generation capacity, while the Southern Springs Solar Energy Project and the Turning Sun Solar Facility will each contribute 100 MW of generation capacity. Further, the First Nations Power Authority is running a request for proposal to obtain an additional 100 MW of solar power. The process is expected to be complete in 2026.

Transmission

- **North/South Interconnection** - This project will provide direct connection between SaskPower's southern and northern transmission systems that are currently connected through Manitoba. The project consists of two 230-kV transmission lines enabling future load growth and reduced reliance on Manitoba Hydro.
- **Taylor Bay – 230-138-kV** - The scope of this project is to construct the new Taylor Bay Switching Station, a new transmission line to connect IF47 to the station, the installation of new grid transformers at Taylor Bay and Island Falls, as well as the installation of reactive support, protection, control and monitoring facilities. This project is required to facilitate the development of new and expanded mining operations in Saskatchewan's far North and will be delivered in multiple stages.
- **Peebles to Rowatt – 230-kV Line** - The scope of this project is to construct a new 230- kV transmission line from Peebles to Rowatt Switching Station to address post-contingency overloading issues, resulting from the addition of 500 MW of long-term firm transmission services from the Southwest Power Pool (SPP) to SaskPower.

- **Southwest Power Pool (SPP) Interconnection – 230-kV Line** - The scope of this project is to facilitate an additional 500-MW of long-term firm transmission service from the SPP to SaskPower. This project includes building a new switching station in the Estevan area, building two new 230-kV transmission lines connecting SaskPower at the new station and SPP international power lines, sectionalizing two existing Boundary Dam to Rowatt lines with in and outs at Rowatt, installing four phase shifting transformers, and installing two static VAR systems.
- **Rowatt Area Development – 230-kV** - The scope of this project is the re-termination of the existing R2F 230-kV line from the Regina South Switching Station to the Rowatt Switching Station and consolidates all Rowatt station work associated with the southeast area system reinforcements.
- **Meadow Lake (ML3) Rebuild – 72-kV** - The scope of this project is to maintain the reliability of the ML3 72-kV line which supplies five distribution substations from the Meadow Lake Switching Station. This project includes the construction of approximately 64 km of new 138-kV (operating at 72-kV) transmission line and the salvage of the old line.
- **Timber Cove to La Ronge (TC5) Rebuild – 72-kV** - The scope of this project is to maintain the reliability on the TC5, 72-kV line, which supplies Timber Cove, Weyakwin, Montreal River and La Ronge substations. The project includes construction of a new 138-kV line (operating at 72-kV) from the Tracey Road Regulator to the La Ronge substation to replace the existing TC5 which is at the end of its useful life. Line protection relays will also be replaced as part of this project.

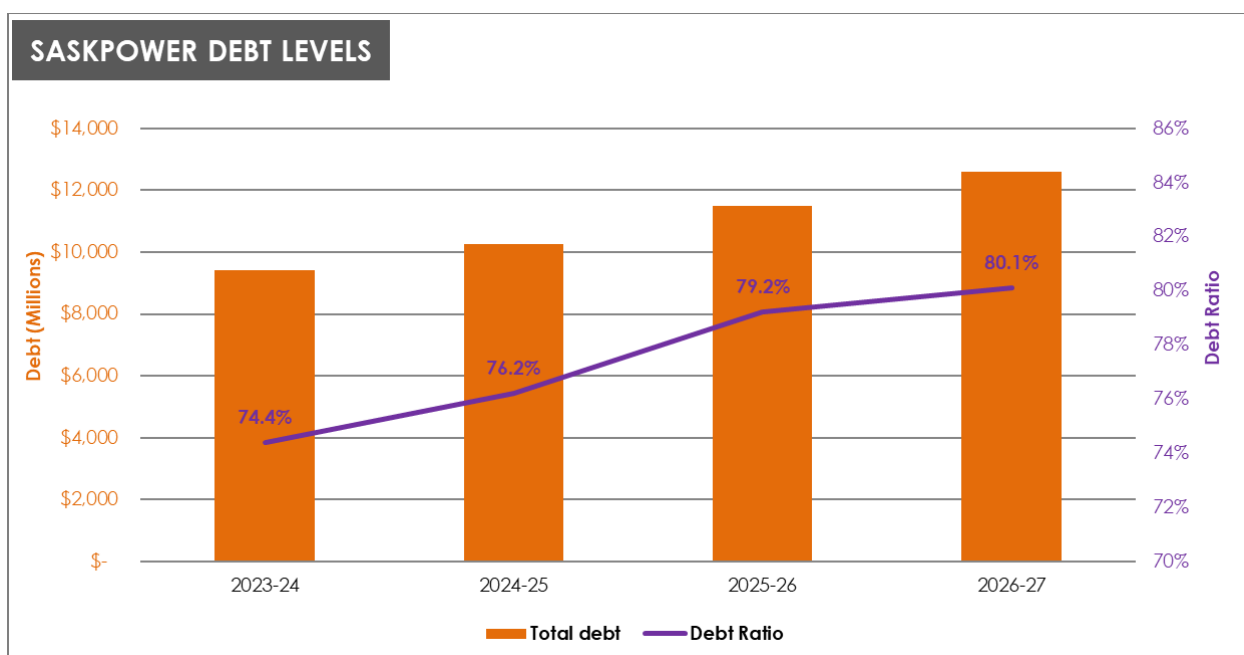
Distribution

- **Underground Primary Cable Mitigation** - The scope of this program is to replace, or life extend underground primary cable due to deterioration of insulation and reliability performance. It specifically targets cable replacements in areas where cable is exhibiting signs of being at or beyond its' life expectancy.
- **Rural Rebuild and Improvement Program** - The scope of this program is to provide for the strategic replacement of the aging rural electrical distribution system.

7.4 Debt

SaskPower's debt is forecasted to increase from \$9.4 billion in 2023-24 to \$12.6 billion by 2026-27. Additional borrowing is required to fund SaskPower's capital investment plans.

The per cent debt ratio is a common financial metric measured as a percentage of total net debt to total capital. The larger the debt ratio, the more a company is leveraged and can be an indicator of financial risk. SaskPower's debt ratio target range is between 60% to 75%. Through the application period, SaskPower is forecasting that the debt ratio will exceed the target, increasing from 74.4% in 2023-24 to 80.1% by 2026-27. SaskPower plans to allow the debt ratio to remain outside the target in the short term to help reduce the need for rate increases. Despite being higher than SaskPower's long-term per cent debt ratio target, the result is within the range of other vertically integrated Canadian electric utilities.



7.5 Financial/productivity indicators

The following assumptions were used to create the two-year forecast. Forecasted key financial indicators are also included below for quick reference.

FINANCIAL/PRODUCTIVITY INDICATORS

	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
Net income (millions)	\$ 76	\$ (147)	\$ 79
Return on equity (%)	2.6%	(5.2%)	2.8%
Per cent debt ratio* (%)	76.2%	79.2%	80.1%
EBITDA interest coverage ratio	2.4	2.0	2.3
Dividend declared (millions)	\$ -	\$ -	\$ -

* Includes finance lease obligations

BUSINESS PLAN ASSUMPTIONS

	ACTUAL 2024-25	FORECAST 2025-26	BUSINESS PLAN 2026-27
Inflation rate (%)	2.0	2.0	2.0
Annual load growth (%)	(1.2)	2.4	3.8
Short-term borrowing rate (%)	2.6	2.5	2.5
Long-term borrowing rate (%)	4.3	4.6	4.6
Weighted average natural gas price (\$/GJ)	3.09	3.33	4.66
Gas consumption (millions of GJs)	102.2	102.0	85.3
Capital expenditures (millions)	\$ 1,423	\$ 1,787	\$ 1,692

8.0 SASKPOWER'S COST OF SERVICE AND RATE DESIGN

SaskPower's budgeting process begins with the load forecast. A business plan is created to meet the anticipated customer demand for electricity. SaskPower's revenue requirement is established based on the costs required to serve customers and is the basis for a request for increased rates. Once overall costs are established, SaskPower allocates the costs to specific customer rates and designs rates that fairly represent the cost to serve each customer.

Our cost allocation and rate design methodology is based on principles and allocation methodologies that are used at most Canadian utilities. The goal of the methodology is to design rates that will collect a level of revenue that reasonably reflects the costs to serve customers in a particular rate class. The guiding principles have some flexibility to ensure that rate structures are not unreasonably complex or difficult to understand for ratepayers.

SaskPower designs rates for different customer rate codes that capture a reasonable amount of revenue to cover the cost to serve customers. In aggregate, the rate codes will collect 100% of the cost allocation. Any design decisions that benefit one rate code will negatively affect other rate codes to ensure that the total allocation is always equal to 100% of SaskPower's costs.

SaskPower relies on the Revenue-To-Revenue-Requirement Ratio (R/RR) to ensure that SaskPower's rates are designed to collect a reasonable amount of revenue. The R/RR calculates the amount of revenue the rates will collect compared to the costs allocated to the customer class. A R/RR of more than 1.0 means that a customer class is being allocated more than the costs to serve its customers, while a R/RR of less than 1.0 means a customer class is being allocated less than the cost to serve its customers. Because cost of service modelling is based on estimates, the industry standard in Canada is that any rate classes that have a R/RR between 0.95 and 1.05 are considered fair and reasonable. Rates that fall outside of this range indicate that a rate class is either paying a premium or receiving a subsidy that is paid for by other rate classes.

From year to year, the R/RR calculation can fluctuate. Many factors contribute to this, such as changes in input costs, changes to class demand at the system peak, and allocation methodology changes. SaskPower rebuilds the cost-of-service model annually based on updated business plans and load forecasts to track the R/RR of customer classes and makes adjustments to rates to ensure that they continue to collect an appropriate level of revenue.

SaskPower's load forecast methodology and cost of service and rate design methodology are independently reviewed every five years to ensure that we continue to meet industry standards. In 2023, Elenchus Research Associates led a public review of our cost-of-service methodology and rate design. At the conclusion of the review, Elenchus released a report confirming that SaskPower's cost-of-service methodology and rate design is in line with industry standards and outlined a set of recommended enhancements. The complete report is available on [saskpower.com](https://www.saskpower.com).

2025-26 impacts

Revenue to Revenue Requirement (R/RR) Ratios 2025-26 rate increase impact

Class of service	R/RR Ratio		R/RR Ratio
	Current rates	Rate increase	
Residential	0.98	3.9%	0.98
Farms	0.96	3.9%	0.95
Commercial	1.05	3.9%	1.04
Power class	1.01	3.9%	1.02
Oilfields	0.97	3.9%	0.97
Reseller	0.95	3.9%	0.96
Total	1.00	3.9%	1.00

*Revenue-to-revenue-requirement ratio (R/RR ratio): The revenue collected from a customer class as a percentage of the total cost to serve that customer class. Our goal is to structure rates to fall within a R/RR ratio range of 0.95 to 1.05.

2025-26 revenue impacts 3.9% flat rate increase effective February 1, 2026

Customer class	Base revenue (existing rates) (\$ millions)	2026 rate increase (%)	Additional revenue from 2026 increase (annualized) (\$ millions)	Monthly revenue increase (per customer)
Residential	\$ 645.4	3.9%	\$ 25.2	\$ 5
Farms	193.5	3.9%	7.5	11
Commercial	575.9	3.9%	22.5	29
Power Class	912.0	3.9%	35.6	26,703
Oilfields	476.4	3.9%	18.6	82
Reseller	100.0	3.9%	3.9	108,333
Total (System)	\$ 2,903.2	3.9%	\$ 113.2	\$ 17

Additional revenue from Feb 1, 2026, increase (prorated) (\$M)	\$ 18.9

* Due to the effective date of February 1, 2026, only 1/6, or approximately \$18.9M of the annualized revenue lift will be realized in 2025-26.

2026-27 impacts

Revenue to Revenue Requirement (R/RR) Ratios

2026-27 rate increase impact

Class of service	R/RR Ratio Starting rates	Rate increase	R/RR Ratio Revised rates
Residential	0.99	3.9%	0.99
Farms	0.97	3.9%	0.96
Commercial	1.04	3.9%	1.03
Power class	1.01	3.9%	1.01
Oilfields	0.98	3.9%	0.98
Reseller	0.95	3.9%	0.96
Total	1.00	3.9%	1.00

*Revenue-to-revenue-requirement ratio (R/RR ratio): The revenue collected from a customer class as a percentage of the total cost to serve that customer class. Our goal is to structure rates to fall within a R/RR ratio range of 0.95 to 1.05.

2026-27 revenue impacts

3.9% flat rate increase effective February 1, 2027

Customer class	Base revenue (existing rates) (\$ millions)	Additional revenue from 2026 increase (\$ millions)	2027 rate increase (%)	Additional revenue from 2027 increase (annualized) (\$ millions)	Monthly revenue increase (per customer)
Residential	\$ 643.6	\$ 25.1	3.9%	\$ 26.1	\$ 5
Farms	197.4	7.7	3.9%	8.0	11
Commercial	559.5	21.8	3.9%	22.7	29
Power Class	970.3	37.8	3.9%	39.3	29,519
Oilfields	496.1	19.3	3.9%	20.1	89
Reseller	103.7	4.0	3.9%	4.2	116,670
Total (System)	\$ 2,970.6	\$ 115.9	3.9%	\$ 120.4	\$ 18

Additional revenue from Feb 1, 2027, increase (prorated) (\$M)	\$ 20.1
Additional revenue from Feb 1, 2026, rate increase (\$M)	\$ 115.9
Total revenue due to rate increases in 2026-27 (\$M)	\$ 135.9

* Due to the effective date of February 1, 2027, only 1/6, or approximately \$20.1M of the annualized revenue lift will be realized in 2026-27.

** The ending revenue in 2025-26 does not equal the starting point in 2026-27 due to changes in the demand for electricity per class, number of customer accounts in the class and changes in usage per customer per class.

9.0 SUMMARY

SaskPower respectfully submits that the request contained in this application is justified and represents a fair and reasonable approach to providing reliable electrical service to its many customers at the lowest possible cost.

SaskPower is requesting a flat 3.9% interim rate increase for all customer classes effective February 1, 2026, and another flat 3.9% increase effective February 1, 2027. With the approval of this application, our company is forecasted to achieve a net income of \$79 million in 2026-27.

APPENDIX A:

Summary of Comparison of Electricity Prices in Major North American Cities – Hydro-Québec

Comparison of power electricity costs

Monthly net bill (before municipal surcharges and taxes) - at April 1, 2024

	Residential	Small Power	Medium Power			Large Power	
Power demand (kW)	-	40	500	1,000	2,500	5,000	50,000
Consumption (kWh)	1,000	10,000	100,000	400,000	1,170,000	3,060,000	30,600,000
Load factor	-	35%	28%	56%	65%	85%	85%
Canadian cities:							
Thermal utilities							
Calgary, AB	\$ 232	\$ 1,782	\$ 19,457	\$ 54,152	\$ 133,310	\$ 319,975	\$ 3,190,711
Edmonton, AB	\$ 240	\$ 2,209	\$ 21,151	\$ 60,818	\$ 166,365	\$ 402,961	\$ 3,400,335
Toronto, ON	\$ 151	\$ 1,486	\$ 21,020	\$ 65,867	\$ 181,221	\$ 333,520	\$ 3,291,630
Ottawa, ON	\$ 143	\$ 1,408	\$ 17,785	\$ 57,027	\$ 166,655	\$ 338,055	\$ 3,243,464
Moncton, NB	\$ 163	\$ 1,637	\$ 17,590	\$ 57,655	\$ 163,238	\$ 299,911	\$ 2,860,940
Halifax, NS	\$ 195	\$ 1,843	\$ 20,146	\$ 63,436	\$ 172,778	\$ 388,568	\$ 3,885,702
Charlottetown, PE	\$ 191	\$ 1,988	\$ 20,279	\$ 67,374	\$ 191,161	\$ 336,272	\$ 3,362,720
Hydro utilities							
Vancouver, BC	\$ 121	\$ 1,224	\$ 12,556	\$ 37,536	\$ 102,235	\$ 248,550	\$ 1,994,755
Winnipeg, MB	\$ 105	\$ 969	\$ 11,430	\$ 31,678	\$ 78,115	\$ 183,573	\$ 1,558,715
Montreal, QC	\$ 80	\$ 1,166	\$ 14,187	\$ 37,493	\$ 93,151	\$ 175,520	\$ 1,661,516
St. John's, NL	\$ 146	\$ 1,362	\$ 13,805	\$ 44,715	\$ 124,292	\$ 311,593	\$ 2,073,232
Thermal average	\$ 187	\$ 1,737	\$ 19,497	\$ 59,763	\$ 163,081	\$ 339,011	\$ 3,212,169
Canadian average	\$ 162	\$ 1,551	\$ 17,330	\$ 52,460	\$ 141,870	\$ 302,610	\$ 2,748,797
Regina, SK	\$ 179	\$ 1,543	\$ 18,549	\$ 51,770	\$ 129,918	\$ 292,824	\$ 2,461,848
SaskPower rank (out of 12 utilities)	8	7	7	5	5	4	5
SaskPower comparison							
Compared to thermal average	96%	89%	95%	87%	80%	86%	77%
Compared to Canadian average	110%	99%	107%	99%	92%	97%	90%
American cities:							
Boston, MA	\$ 318	\$ 3,091	\$ 32,678	\$ 97,275	\$ 254,446	\$ 618,628	\$ 5,095,203
Chicago, IL	\$ 167	\$ 1,444	\$ 14,327	\$ 38,972	\$ 106,405	\$ 248,620	\$ 1,938,549
Detroit, MI	\$ 226	\$ 1,606	\$ 15,762	\$ 45,363	\$ 108,728	\$ 251,339	\$ 2,397,785
Houston, TX	\$ 140	\$ 1,206	\$ 13,240	\$ 43,519	\$ 109,153	\$ 267,134	\$ 2,431,554
Miami, FL	\$ 121	\$ 1,205	\$ 14,137	\$ 39,072	\$ 104,821	\$ 246,641	\$ 2,097,313
Nashville, TN	\$ 153	\$ 1,560	\$ 19,474	\$ 52,143	\$ 143,738	\$ 333,337	\$ 2,253,984
New York, NY	\$ 329	\$ 2,675	\$ 30,217	\$ 79,732	\$ 202,385	\$ 474,714	\$ 4,745,503
Portland, OR	\$ 127	\$ 1,209	\$ 13,459	\$ 38,771	\$ 95,493	\$ 225,390	\$ 2,099,099
San Francisco, CA	\$ 365	\$ 3,104	\$ 36,345	\$ 97,650	\$ 194,667	\$ 468,123	\$ 4,664,836
Seattle, WA	\$ 158	\$ 1,323	\$ 12,608	\$ 44,732	\$ 127,000	\$ 325,582	\$ 3,044,591
North American average	\$ 184	\$ 1,684	\$ 18,646	\$ 54,852	\$ 143,149	\$ 322,310	\$ 2,897,908
SaskPower rank (out of 22 utilities)	14	12	13	11	11	9	11
SaskPower comparison							
Compared to N.A. average	97%	92%	99%	94%	91%	91%	85%

Comparison of power electricity rates

Average price (cents/kWh) - on April 1, 2024

	Residential	Small Power	Medium Power			Large Power	
Power demand (kW)	-	40 kW	500 kW	1,000 kW	2,500 kW	5,000 kW	50,000 kW
Consumption (kWh)	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor	-	35%	28%	56%	65%	85%	85%
Canadian cities:							
Thermal utilities							
Calgary, AB	23.2	17.8	19.5	13.5	11.4	10.5	10.4
Edmonton, AB	24.0	22.1	21.2	15.2	14.2	13.2	11.1
Toronto, ON	15.1	14.9	21.0	16.5	15.5	10.9	10.8
Ottawa, ON	14.3	14.1	17.8	14.3	14.2	11.1	10.6
Moncton, NB	16.3	16.4	17.6	14.4	14.0	9.8	9.4
Halifax, NS	19.5	18.4	20.2	15.9	14.8	12.7	12.7
Charlottetown, PE	19.1	19.9	20.3	16.8	16.3	11.0	11.0
Hydro utilities							
Vancouver, BC	12.1	12.2	12.6	9.4	8.7	8.1	6.5
Winnipeg, MB	10.5	9.7	11.4	7.9	6.7	6.0	5.1
St. John's, NL	14.6	13.6	13.8	11.2	10.6	10.2	6.8
Montreal, QC	8.1	11.7	14.2	9.4	8.0	5.7	5.4
Thermal average	18.7	17.4	19.5	14.9	13.9	11.1	10.5
Canadian average	16.1	15.5	17.2	13.1	12.2	9.9	9.1
Regina, SK	17.9	15.4	18.6	12.9	11.1	9.6	8.1
SaskPower rank (out of 12 utilities)	8	7	7	5	5	4	5
SaskPower comparison							
Compared to thermal average	96%	89%	95%	87%	80%	86%	77%
Compared to Canadian average	111%	99%	108%	99%	91%	96%	89%
American cities:							
Boston, MA	\$ 47	\$ 46	\$ 42	\$ 32	\$ 28	\$ 26	\$ 22
Chicago, IL	\$ 23	\$ 22	\$ 18	\$ 14	\$ 12	\$ 11	\$ 9
Detroit, MI	\$ 28	\$ 21	\$ 20	\$ 14	\$ 12	\$ 10	\$ 10
Houston, TX	\$ 16	\$ 18	\$ 19	\$ 16	\$ 14	\$ 14	\$ 13
Miami, FL	\$ 17	\$ 16	\$ 19	\$ 13	\$ 12	\$ 11	\$ 10
Nashville, TN	\$ 18	\$ 18	\$ 22	\$ 15	\$ 14	\$ 13	\$ 8
New York, NY	\$ 58	\$ 44	\$ 50	\$ 33	\$ 24	\$ 21	\$ 21
Portland, OR	\$ 21	\$ 17	\$ 19	\$ 15	\$ 13	\$ 12	\$ 11
San Francisco, CA	\$ 60	\$ 56	\$ 66	\$ 43	\$ 30	\$ 26	\$ 26
Seattle, WA	\$ 19	\$ 16	\$ 16	\$ 14	\$ 14	\$ 13	\$ 12
North American average	\$ 23	\$ 21	\$ 23	\$ 17	\$ 14	\$ 13	\$ 11
SaskPower rank (out of 22 utilities)	10	7	9	5	5	4	5
SaskPower comparison							
Compared to N.A. average	78%	74%	82%	78%	77%	76%	71%

APPENDIX B:

Rate proposals

SaskPower
Rate Proposal
RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E01 Existing E01 Proposed	City	29.99 31.16		14.895 15.476					29.99 31.16	
E03 Existing E03 Proposed	Rural, Rural Resort	29.99 31.16		14.895 15.476					29.99 31.16	

SaskPower Rate Proposal DIESEL

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E04 Existing E04 Proposed	Residential Diesel	29.99 31.16	650 650	14.895 15.476	58.148 60.416				29.99 31.16	
E35 Existing E35 Proposed	General Service	44.62 46.36		15.482 16.086	53.333 55.413				44.62 46.36	

SaskPower Rate Proposal FARM

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL * DEMAND	NOTES
E34 Existing	Farm	46.22	16,000	13.332	5.602	50	0.000	15.137	46.22	4.869	/KV.A max demand over 50
E34 Proposed		48.02	16,000	13.852	5.820	50	0.000	15.727	48.02	5.059	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower Rate Proposal IRRIGATION

RATE CODE	DESCRIPTION	BASIC (\$/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/hp)	BASIC	MINIMUM BILL DEMAND	NOTES
E19 Existing E19 Proposed	Farm - SaskPower Supplied Transformation	635.06 659.83		9.359 9.724					635.06 659.83		
E37 Existing E37 Proposed	General Service - SaskPower Supplied Transformation	273.13 283.78		10.360 10.764			27.481 28.553		273.13 283.78	27.481 /KV.A max demand 28.553 /KV.A max demand	
E41 Existing E41 Proposed	Mains - Interruptible - closed to new customers	1,197.40 1,244.10		8.018 8.331					1,197.40 1,244.10		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower Rate Proposal GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL * DEMAND	NOTES
E05 Existing E05 Proposed	Urban - SaskPower Supplied Transformation	73.00 75.85	16,750 16,750	11.515 11.964	7.222 7.504	50 50	0.000 0.000	20.820 21.632	73.00 75.85	4.869 5.059	/KV.A max demand over 50 /KV.A max demand over 50
E06 Existing E06 Proposed	Rural - SaskPower Supplied Transformation	73.00 75.85	15,500 15,500	11.515 11.964	7.222 7.504	50 50	0.000 0.000	20.820 21.632	73.00 75.85	4.869 5.059	/KV.A max demand over 50 /KV.A max demand over 50
E07 Existing E07 Proposed	Urban - Customer Owned Transformation	278.68 289.55		7.014 7.288			19.285 20.037		278.68 289.55	4.869 5.059	/KV.A max demand /KV.A max demand
E08 Existing E08 Proposed	Rural - Customer Owned Transformation	278.68 289.55		7.014 7.288			19.285 20.037		278.68 289.55	4.869 5.059	/KV.A max demand /KV.A max demand
E10 Existing E10 Proposed	Customer Owned Transformation	288.26 299.50		5.464 5.677			14.920 15.502		288.26 299.50	4.869 5.059	/KV.A max demand /KV.A max demand
E12 Existing E12 Proposed	Customer Owned Transformation	327.57 340.35		5.328 5.536			14.455 15.019		327.57 340.35	4.869 5.059	/KV.A max demand /KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower
Rate Proposal
GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	Energy Block 1		Energy Block 1		Energy Balance		Demand Block 1		Demand Block 1		Demand Balance		BASIC		MINIMUM BILL *		NOTES
		Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	41.18	42.79	4.869	5.059	
E75 Existing E75 Proposed	Urban - SaskPower Supplied Transformation	14,500 14,500	15,016 15,602	15,016 15,602	6,153 6,393	50 50	0,000 0,000	20,008 20,788	41.18 42.79	4.869 5.059	20,008 20,788	41.18 42.79	4.869 5.059	41.18 42.79	4.869 5.059	/KV.A max demand over 50	/KV.A max demand over 50	
E76 Existing E76 Proposed	Rural - SaskPower Supplied Transformation	13,000 13,000	15,016 15,602	15,016 15,602	6,153 6,393	50 50	0,000 0,000	20,008 20,788	41.18 42.79	4.869 5.059	20,008 20,788	41.18 42.79	4.869 5.059	41.18 42.79	4.869 5.059	/KV.A max demand over 50	/KV.A max demand over 50	
E77 Existing E77 Proposed	Urban - Customer Owned Transformation	14,500 14,500	15,016 15,602	15,016 15,602	6,153 6,393	50 50	0,000 0,000	19,308 20,061	41.18 42.79	4.869 5.059	19,308 20,061	41.18 42.79	4.869 5.059	41.18 42.79	4.869 5.059	/KV.A max demand over 50	/KV.A max demand over 50	
E78 Existing E78 Proposed	Rural - Customer Owned Transformation	13,000 13,000	15,016 15,602	15,016 15,602	6,153 6,393	50 50	0,000 0,000	19,308 20,061	41.18 42.79	4.869 5.059	19,308 20,061	41.18 42.79	4.869 5.059	41.18 42.79	4.869 5.059	/KV.A max demand over 50	/KV.A max demand over 50	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower
Rate Proposal
GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E15 Existing E15 Proposed	Unmetered - Miscellaneous			4.521 4.697					21.25 22.08	
E16 Existing E16 Proposed	Unmetered - Power Supply Units			78.590 81.655					78.59 81.66	
E17 Existing E17 Proposed	Unmetered - Cable Television Rectifiers			1.649 1.713					32.93 34.21	
E18 Existing E18 Proposed	Unmetered - X-rays			4.511 4.687						

SaskPower Rate Proposal OILFIELD

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E43 Existing E43 Proposed	Standard Oilfield	78.57 81.63		7.171 7.451			17.796 18.490		78.57 81.63	17.796 18.490	/KVA max demand /KVA max demand	
E44 Existing E44 Proposed	Standard Oilfield	78.57 81.63		7.171 7.451			17.096 17.763		78.57 81.63	17.096 17.763	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower Rate Proposal POWER - OILFIELD

RATE CODE	DESCRIPTION	Energy Block 1		Energy Balance		Demand Block 1		Demand Block 1		Demand Balance		MINIMUM BILL *	
		BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	BASIC (\$/month)	Rate (\$/kVA)	DEMAND	NOTES
E46 Existing E46 Proposed	25kV - Customer Owned Transformation	6,759.21 7,022.82		6.253 6.497			17,998 18,700			6,759.21 7,022.82		17,998 18,700	/KV.A max demand /KV.A max demand
E47 Existing E47 Proposed	72kV - Customer Owned Transformation	7,845.52 8,151.50		6.208 6.450			14,632 15,203			7,845.52 8,151.50		14,632 15,203	/KV.A max demand /KV.A max demand
E48 Existing E48 Proposed	138kV - Customer Owned Transformation	8,403.75 8,731.50		6.025 6.260			11,586 12,038			8,403.75 8,731.50		11,586 12,038	/KV.A max demand /KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower Rate Proposal POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	Energy Block 1		On-Peak Energy		Off-Peak Energy		Demand Block 1		Demand Balance		MINIMUM BILL *	
		BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	DEMAND	NOTES
E86 Existing E86 Proposed	25kV - Customer Owned Transformation	6,759.21 7,022.82		6.825 7.070		5.825 6.070			17,998 18,700			17,998 18,700	/KV.A max demand /KV.A max demand
E87 Existing E87 Proposed	72kV - Customer Owned Transformation	7,845.52 8,151.50		6.780 7.023		5.780 6.023			14,632 15,203			14,632 15,203	/KV.A max demand /KV.A max demand
E88 Existing E88 Proposed	138kV - Customer Owned Transformation	8,403.75 8,731.50		6.597 6.833		5.597 5.833			11,586 12,038			11,586 12,038	/KV.A max demand /KV.A max demand

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E22 Existing E22 Proposed	25kV - Customer Owned Transformation	6,759.21 7,022.82		6.253 6.497			17.998 18.700		6,759.21 7,022.82	17.998 18.700	/KV.A max demand /KV.A max demand	
E23 Existing E23 Proposed	72kV - Customer Owned Transformation	7,845.52 8,151.50		6.208 6.450			14.632 15.203		7,845.52 8,151.50	14.632 15.203	/KV.A max demand /KV.A max demand	
E24 Existing E24 Proposed	138kV - Customer Owned Transformation	8,403.75 8,731.50		6.025 6.260			11.586 12.038		8,403.75 8,731.50	11.586 12.038	/KV.A max demand /KV.A max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E82 Existing E82 Proposed	25kV - Customer Owned Transformation	6,759.21 7,022.82		6.825 7.070	5.825 6.070		17.998 18.700		6,759.21 7,022.82	17.998 18.700	/KV.A max demand /KV.A max demand	
E83 Existing E83 Proposed	72kV - Customer Owned Transformation	7,845.52 8,151.50		6.780 7.023	5.780 6.023		14.632 15.203		7,845.52 8,151.50	14.632 15.203	/KV.A max demand /KV.A max demand	
E84 Existing E84 Proposed	138kV - Customer Owned Transformation	8,403.75 8,731.50		6.597 6.833	5.597 5.833		11.586 12.038		8,403.75 8,731.50	11.586 12.038	/KV.A max demand /KV.A max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower Rate Proposal RESELLER

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E31 Existing E31 Proposed	Swift Current 25 kV (Non-Totalized)	6,842.37 7,109.22		5.631 5.851			20.872 21.686		6,842.37 7,109.22	20.872 21.686	/KVA max demand /KVA max demand	
E32 Existing E32 Proposed	Swift Current 138 kV - (Non-Totalized)	7,844.11 8,150.03		5.467 5.680			18.654 19.382		7,844.11 8,150.03	18.654 19.382	/KVA max demand /KVA max demand	
E33 Existing E33 Proposed	Saskatoon 138kV - (Totalized)	16,365.85 17,004.12		5.121 5.321			20.150 20.936		16,365.85 17,004.12	20.150 20.936	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly (\$/month)	Proposed Monthly (\$/month)
S17	70 W	\$12.36	\$12.84
S18	100 W	\$14.44	\$15.00
S19	150 W	\$16.79	\$17.44
S20	150 W Cont.	\$20.74	\$21.55
S21	250 W	\$21.79	\$22.64
S22	250 W Cont.	\$27.82	\$28.90
S23	400 W	\$28.25	\$29.35

SaskPower
Rate Proposal
RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E01 Existing E01 Proposed	City	31.16 32.37		15.476 16.079					31.16 32.37	
E03 Existing E03 Proposed	Rural, Rural Resort	31.16 32.37		15.476 16.079					31.16 32.37	

SaskPower
Rate Proposal
DIESEL

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E04 Existing	Residential Diesel	31.16	650	15.476	60.416				31.16	
E04 Proposed		32.37	650	16.079	62.772				32.37	
E35 Existing	General Service	46.36		16.086	55.413				46.36	
E35 Proposed		48.17		16.713	57.574				48.17	

SaskPower
Rate Proposal
FARM

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL * DEMAND	NOTES
E34 Existing	Farm	48.02	16,000	13.852	5.820	50	0.000	15.727	48.02	5.059	/KV.A max demand over 50
E34 Proposed		49.90	16,000	14.392	6.047	50	0.000	16.341	49.90	5.256	/KV.A max demand over 50

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower Rate Proposal IRRIGATION

RATE CODE	DESCRIPTION	BASIC (\$/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/hp)	BASIC	DEMAND	MINIMUM BILL	NOTES
E19 Existing E19 Proposed	Farm - SaskPower Supplied Transformation	659.83 685.56		9.724 10.103					659.83 685.56			
E37 Existing E37 Proposed	General Service - SaskPower Supplied Transformation	283.78 294.85		10.764 11.184			28.553 29.666		283.78 294.85	28.553 29.666	/KV.A max demand /KV.A max demand	
E41 Existing E41 Proposed	Mains - Interruptible - closed to new customers	1244.10 1292.62		8.331 8.656					1,244.10 1,292.62			

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower Rate Proposal GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL * DEMAND	NOTES
E05 Existing E05 Proposed	Urban - SaskPower Supplied Transformation	75.85 78.81	16,750 16,750	11.964 12.431	7.504 7.796	50 50	0.000 0.000	21.632 22.476	75.85 78.81	5.059 /KV.A max demand over 50 5.256 /KV.A max demand over 50	
E06 Existing E06 Proposed	Rural - SaskPower Supplied Transformation	75.85 78.81	15,500 15,500	11.964 12.431	7.504 7.796	50 50	0.000 0.000	21.632 22.476	75.85 78.81	5.059 /KV.A max demand over 50 5.256 /KV.A max demand over 50	
E07 Existing E07 Proposed	Urban - Customer Owned Transformation	289.55 300.84		7.288 7.572			20.037 20.819		289.55 300.84	5.059 /KV.A max demand 5.256 /KV.A max demand	
E08 Existing E08 Proposed	Rural - Customer Owned Transformation	289.55 300.84		7.288 7.572			20.037 20.819		289.55 300.84	5.059 /KV.A max demand 5.256 /KV.A max demand	
E10 Existing E10 Proposed	Customer Owned Transformation	299.50 311.18		5.677 5.899			15.502 16.106		299.50 311.18	5.059 /KV.A max demand 5.256 /KV.A max demand	
E12 Existing E12 Proposed	Customer Owned Transformation	340.35 353.62		5.536 5.752			15.019 15.604		340.35 353.62	5.059 /KV.A max demand 5.256 /KV.A max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower
Rate Proposal
GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC \$/month	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E75 Existing E75 Proposed	Urban - SaskPower Supplied Transformation	42.79 44.45	14,500 14,500	15.602 16.210	6.393 6.642	50 50	0.000 0.000	20.788 21.599	42.79 44.45	5.059 5.256	/KV.A max demand over 50 /KV.A max demand over 50	
E76 Existing E76 Proposed	Rural - SaskPower Supplied Transformation	42.79 44.45	13,000 13,000	15.602 16.210	6.393 6.642	50 50	0.000 0.000	20.788 21.599	42.79 44.45	5.059 5.256	/KV.A max demand over 50 /KV.A max demand over 50	
E77 Existing E77 Proposed	Urban - Customer Owned Transformation	42.79 44.45	14,500 14,500	15.602 16.210	6.393 6.642	50 50	0.000 0.000	20.061 20.843	42.79 44.45	5.059 5.256	/KV.A max demand over 50 /KV.A max demand over 50	
E78 Existing E78 Proposed	Rural - Customer Owned Transformation	42.79 44.45	13,000 13,000	15.602 16.210	6.393 6.642	50 50	0.000 0.000	20.061 20.843	42.79 44.45	5.059 5.256	/KV.A max demand over 50 /KV.A max demand over 50	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding six months.

SaskPower
Rate Proposal
GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	MINIMUM BILL
E15 Existing E15 Proposed	Unmetered - Miscellaneous			4.697 4.881					22.08 22.98	
E16 Existing E16 Proposed	Unmetered - Power Supply Units			81.655 84.840					81.66 84.84	
E17 Existing E17 Proposed	Unmetered - Cable Television Rectifiers			1.713 1.780					34.21 35.61	
E18 Existing E18 Proposed	Unmetered - X-rays			4.687 4.870						

SaskPower Rate Proposal OILFIELD

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E43 Existing E43 Proposed	Standard Oilfield	81.63 84.82		7.451 7.741			18.490 19.211		81.63 84.82	18.490 19.211	/KVA max demand /KVA max demand	
E44 Existing E44 Proposed	Standard Oilfield	81.63 84.82		7.451 7.741			17.763 18.455		81.63 84.82	17.763 18.455	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC		Energy Block 1		Energy Balance		Demand Block 1		Demand Block 1		Demand Balance		MINIMUM BILL *		NOTES
		(\$/month)	Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	DEMAND	DEMAND	
E46 Existing E46 Proposed	25kV - Customer Owned Transformation	7,022.82 7,296.71		6.497 6.750				18.700 19.429				18.700 19.429		18.700 19.429	/KV.A max demand /KV.A max demand	
E47 Existing E47 Proposed	72kV - Customer Owned Transformation	8,151.50 8,469.40		6.450 6.702				15.203 15.796				15.203 15.796		15.203 15.796	/KV.A max demand /KV.A max demand	
E48 Existing E48 Proposed	138kV - Customer Owned Transformation	8,731.50 9,072.02		6.260 6.504				12.038 12.507				12.038 12.507		12.038 12.507	/KV.A max demand /KV.A max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC		Energy Block 1		On-Peak Energy		Off-Peak Energy		Demand Block 1		Demand Balance		MINIMUM BILL *		NOTES
		(\$/month)	Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	DEMAND	DEMAND	
E86 Existing E86 Proposed	25kV - Customer Owned Transformation	7,022.82 7,296.71		7.070 7.323		6.070 6.323				18.700 19.429		18.700 19.429		18.700 19.429	/KV.A max demand /KV.A max demand	
E87 Existing E87 Proposed	72kV - Customer Owned Transformation	8,151.50 8,469.40		7.023 7.274		6.023 6.274				15.203 15.796		15.203 15.796		15.203 15.796	/KV.A max demand /KV.A max demand	
E88 Existing E88 Proposed	138kV - Customer Owned Transformation	8,731.50 9,072.02		6.833 7.077		5.833 6.077				12.038 12.507		12.038 12.507		12.038 12.507	/KV.A max demand /KV.A max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC		Energy Block 1		Energy Balance		Demand Block 1		Demand Block 1		Demand Balance		MINIMUM BILL *		NOTES
		(\$/month)	Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	DEMAND	DEMAND	
E22 Existing E22 Proposed	25kV - Customer Owned Transformation	7,022.82 7,296.71		6.497 6.750					18.700 19.429					18.700 19.429	/KVA max demand /KVA max demand	
E23 Existing E23 Proposed	72kV - Customer Owned Transformation	8,151.50 8,469.40		6.450 6.702					15.203 15.796					15.203 15.796	/KVA max demand /KVA max demand	
E24 Existing E24 Proposed	138kV - Customer Owned Transformation	8,731.50 9,072.02		6.260 6.504					12.038 12.507					12.038 12.507	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC		Energy Block 1		On-Peak Energy		Off-Peak Energy		Demand Block 1		Demand Balance		MINIMUM BILL *		NOTES
		(\$/month)	Size (kW.h/month)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Rate (cents/kW.h)	Size (kVA)	Rate (\$/kVA)	Rate (\$/kVA)	Rate (\$/kVA)	DEMAND	DEMAND	
E82 Existing E82 Proposed	25kV - Customer Owned Transformation	7,022.82 7,296.71		7.070 7.323		6.070 6.323				18.700 19.429				18.700 19.429	/KVA max demand /KVA max demand	
E83 Existing E83 Proposed	72kV - Customer Owned Transformation	8,151.50 8,469.40		7.023 7.274		6.023 6.274				15.203 15.796				15.203 15.796	/KVA max demand /KVA max demand	
E84 Existing E84 Proposed	138kV - Customer Owned Transformation	8,731.50 9,072.02		6.833 7.077		5.833 6.077				12.038 12.507				12.038 12.507	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower Rate Proposal RESELLER

RATE CODE	DESCRIPTION	BASIC (\$/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate (\$/kVA)	Demand Balance Rate (\$/kVA)	BASIC	DEMAND	MINIMUM BILL *	NOTES
E31 Existing E31 Proposed	Swift Current 25 kV (Non-Totalized)	7,109.22 7,386.48		5.851 6.079			21.686 22.532		7,109.22 7,386.48	21.686 22.532	/KVA max demand /KVA max demand	
E32 Existing E32 Proposed	Swift Current 138 kV - (Non-Totalized)	8,150.03 8,467.88		5.680 5.902			19.382 20.137		8,150.03 8,467.88	19.382 20.137	/KVA max demand /KVA max demand	
E33 Existing E33 Proposed	Saskatoon 138kV - (Totalized)	17,004.12 17,667.28		5.321 5.528			20.936 21.752		17,004.12 17,667.28	20.936 21.752	/KVA max demand /KVA max demand	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly (\$/month)	Proposed Monthly (\$/month)
S17	70 W	\$12.84	\$13.34
S18	100 W	\$15.00	\$15.59
S19	150 W	\$17.44	\$18.13
S20	150 W Cont.	\$21.55	\$22.39
S21	250 W	\$22.64	\$23.52
S22	250 W Cont.	\$28.90	\$30.03
S23	400 W	\$29.35	\$30.50

APPENDIX C:

Rate change impacts

2025-26
Rate Change Impacts on E01 by Energy Intervals
Urban Residential

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	14.895	15.476	3.9%
Basic Charge: (\$/month)	29.99	31.16	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	- 1	4,864	1.98	3,508	0.19	1.52	3.9	3.9	3.9
100 to 200	- 2	15,300	6.22	28,792	1.55	2.08	3.9	3.9	3.9
200 to 300	- 3	25,056	10.18	75,862	4.09	2.64	3.9	3.9	3.9
300 to 400	- 4	29,604	12.03	124,690	6.72	3.21	3.9	3.9	3.9
400 to 500	- 5	32,473	13.20	175,396	9.45	3.79	3.9	3.9	3.9
500 to 600	- 6	31,537	12.82	207,809	11.20	4.36	3.9	3.9	3.9
600 to 700	- 7	26,583	10.81	206,890	11.15	4.94	3.9	3.9	3.9
700 to 800	- 8	21,170	8.61	189,973	10.24	5.51	3.9	3.9	3.9
800 to 900	- 9	16,032	6.52	163,041	8.79	6.09	3.9	3.9	3.9
900 to 1000	- 10	11,778	4.79	133,855	7.21	6.67	3.9	3.9	3.9
1000 to 1100	- 11	8,488	3.45	106,692	5.75	7.26	3.9	3.9	3.9
1100 to 1200	- 12	6,169	2.51	84,972	4.58	7.84	3.9	3.9	3.9
1200 to 1300	- 13	4,321	1.76	64,655	3.48	8.41	3.9	3.9	3.9
1300 to 1400	- 14	3,081	1.25	49,826	2.69	9.00	3.9	3.9	3.9
1400 to 1500	- 15	2,246	0.91	38,978	2.10	9.57	3.9	3.9	3.9
1500 to 2000	- 16	5,024	2.04	102,332	5.52	11.03	3.9	3.9	3.9
2000 to 2500	- 17	1,384	0.56	36,603	1.97	13.97	3.9	3.9	3.9
2500 to 3000	- 18	467	0.19	15,175	0.82	16.90	3.9	3.9	3.9
3000 to 3500	- 19	165	0.07	6,349	0.34	19.80	3.9	3.9	3.9
3500 to 4000	- 20	87	0.04	3,879	0.21	22.75	3.9	3.9	3.9
4000 to 4500	- 21	27	0.01	1,362	0.07	25.60	3.9	3.9	3.9
4500 to 5000	- 22	10	0.00	559	0.03	28.24	3.9	3.9	3.9
5000 to 6000	- 23	17	0.01	1,095	0.06	32.36	3.9	3.9	3.9
6000 to 7000	- 24	19	0.01	1,475	0.08	38.76	3.9	3.9	3.9
7000 to 8000	- 25	12	0.00	1,082	0.06	44.84	3.9	3.9	3.9
8000 to 9000	- 26	7	0.00	723	0.04	51.18	3.9	3.9	3.9
9000 to 10000	- 27	5	0.00	572	0.03	56.53	3.9	3.9	3.9
> 10000	- 28	83	0.03	29,276	1.58	171.95	3.9	3.9	3.9
Total		246,009	100.00	1,855,424	100.00	4.82	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E03 by Energy Intervals
Rural Residential

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	14.895	15.476	3.9%
Basic Charge: (\$/month)	29.99	31.16	Based on 2024 Billing.

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	- 1	1,435	2.55	948	0.12	1.49	3.9	3.9	3.9
100 to 200	- 2	1,709	3.04	3,102	0.41	2.05	3.9	3.9	3.9
200 to 300	- 3	2,008	3.57	6,060	0.79	2.63	3.9	3.9	3.9
300 to 400	- 4	2,531	4.50	10,722	1.40	3.22	3.9	3.9	3.9
400 to 500	- 5	3,240	5.76	17,541	2.30	3.79	3.9	3.9	3.9
500 to 600	- 6	3,630	6.45	23,996	3.14	4.37	3.9	3.9	3.9
600 to 700	- 7	4,015	7.13	31,359	4.10	4.95	3.9	3.9	3.9
700 to 800	- 8	4,001	7.11	35,965	4.71	5.52	3.9	3.9	3.9
800 to 900	- 9	3,799	6.75	38,707	5.07	6.10	3.9	3.9	3.9
900 to 1000	- 10	3,547	6.30	40,401	5.29	6.68	3.9	3.9	3.9
1000 to 1100	- 11	3,205	5.69	40,310	5.28	7.26	3.9	3.9	3.9
1100 to 1200	- 12	2,904	5.16	40,020	5.24	7.84	3.9	3.9	3.9
1200 to 1300	- 13	2,518	4.47	37,745	4.94	8.43	3.9	3.9	3.9
1300 to 1400	- 14	2,233	3.97	36,142	4.73	9.00	3.9	3.9	3.9
1400 to 1500	- 15	1,935	3.44	33,621	4.40	9.58	3.9	3.9	3.9
1500 to 2000	- 16	6,613	11.75	136,915	17.92	11.19	3.9	3.9	3.9
2000 to 2500	- 17	3,467	6.16	92,574	12.12	14.08	3.9	3.9	3.9
2500 to 3000	- 18	1,762	3.13	57,614	7.54	16.97	3.9	3.9	3.9
3000 to 3500	- 19	922	1.64	35,623	4.66	19.82	3.9	3.9	3.9
3500 to 4000	- 20	388	0.69	17,314	2.27	22.63	3.9	3.9	3.9
4000 to 4500	- 21	187	0.33	9,451	1.24	25.34	3.9	3.9	3.9
4500 to 5000	- 22	99	0.18	5,588	0.73	27.96	3.9	3.9	3.9
5000 to 6000	- 23	84	0.15	5,413	0.71	31.08	3.9	3.9	3.9
6000 to 7000	- 24	26	0.05	2,008	0.26	34.80	3.9	3.9	3.9
7000 to 8000	- 25	15	0.03	1,329	0.17	37.83	3.9	3.9	3.9
8000 to 9000	- 26	4	0.01	409	0.05	38.80	3.9	3.9	3.9
9000 to 10000	- 27	4	0.01	447	0.06	39.96	3.9	3.9	3.9
> 10000	- 28	14	0.02	2,732	0.36	42.74	3.9	3.9	3.9
Total		56,295	100.00	764,057	100.00	7.71	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E04 by Energy Intervals
Rural Residential - Residential Diesel

Rate Breakdown	Existing	Proposed	Based on Rate Class
First Block Size (kW.h/month)	650	650	3.9%
Energy Rate (cents/kW.h): First Block	14.895	15.476	
Balance	58.148	60.416	
Basic Charge: (\$/month)	29.99	31.16	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 300	-	1	3	50.00	6	18.43	1.14	3.9	3.9	3.9
300 to 400	-	2	-	0.00	-	0.00	0.00	0.0	0.0	0.0
400 to 900	-	3	2	33.33	18	49.85	6.50	3.9	3.9	3.9
900 to 1000	-	4	1	16.67	11	31.73	10.25	3.9	3.9	3.9
> 1000	-	5	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			6	100.00	35	100.00	4.45	0.0	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E34 by Energy Intervals
Farm

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		16,000	16,000	
Energy Rate (cents/kW.h): First Block		13.332	13.852	
	Balance	5.602	5.820	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	15.137	15.727	
Basic Charge (\$/month):		46.22	48.02	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	-	1	2,651	6.43	1,246	0.12	2.00	3.9	3.9	3.9
100 to 200	-	2	1,470	3.56	2,636	0.26	2.58	3.9	3.9	3.9
200 to 300	-	3	1,287	3.12	3,827	0.38	3.09	3.9	3.9	3.9
300 to 400	-	4	1,314	3.19	5,522	0.55	3.62	3.9	3.9	3.9
400 to 500	-	5	1,338	3.24	7,242	0.72	4.15	3.9	3.9	3.9
500 to 600	-	6	1,477	3.58	9,769	0.97	4.67	3.9	3.9	3.9
600 to 700	-	7	1,646	3.99	12,827	1.27	5.18	3.9	3.9	3.9
700 to 800	-	8	1,674	4.06	15,094	1.50	5.71	3.9	3.9	3.9
800 to 900	-	9	1,747	4.24	17,822	1.77	6.22	3.9	3.9	3.9
900 to 1000	-	10	1,627	3.95	18,542	1.84	6.75	3.9	3.9	3.9
1000 to 1100	-	11	1,644	3.99	20,716	2.05	7.26	3.9	3.9	3.9
1100 to 1200	-	12	1,553	3.77	21,424	2.12	7.79	3.9	3.9	3.9
1200 to 1300	-	13	1,453	3.52	21,790	2.16	8.30	3.9	3.9	3.9
1300 to 1400	-	14	1,428	3.46	23,121	2.29	8.82	3.9	3.9	3.9
1400 to 1500	-	15	1,261	3.06	21,935	2.17	9.35	3.9	3.9	3.9
1500 to 1600	-	16	1,276	3.09	23,746	2.35	9.87	3.9	3.9	3.9
1600 to 1700	-	17	1,115	2.70	22,069	2.19	10.38	3.9	3.9	3.9
1700 to 1800	-	18	1,066	2.58	22,380	2.22	10.91	3.9	3.9	3.9
1800 to 1900	-	19	1,000	2.42	22,186	2.20	11.42	3.9	3.9	3.9
1900 to 2000	-	20	979	2.37	22,893	2.27	11.96	3.9	3.9	3.9
2000 to 2500	-	21	3,798	9.21	101,980	10.11	13.46	3.9	3.9	3.9
2500 to 3000	-	22	2,601	6.31	85,280	8.45	16.08	3.9	3.9	3.9
3000 to 3500	-	23	1,771	4.29	68,619	6.80	18.64	3.9	3.9	3.9
3500 to 4000	-	24	1,122	2.72	50,291	4.98	21.33	3.9	3.9	3.9
4000 to 4500	-	25	745	1.81	37,838	3.75	23.91	3.9	3.9	3.9
4500 to 5000	-	26	534	1.29	30,379	3.01	26.60	3.9	3.9	3.9
5000 to 10000	-	27	1,185	2.87	90,939	9.01	35.53	3.9	3.9	3.9
10000 to 15000	-	28	147	0.36	21,415	2.12	66.81	3.9	3.9	3.9
15000 to 20000	-	29	64	0.16	13,149	1.30	92.42	3.9	3.9	3.9
20000 to 25000	-	30	38	0.09	10,343	1.03	116.18	3.9	3.9	3.9
> 25000	-	31	227	0.55	181,849	18.03	266.97	3.9	3.9	3.9
Total			41,238	100.00	1,008,869	100.00	11.99	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E05 by Energy Intervals
General Service - Large
Urban - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		16,750	16,750	
Energy Rate (cents/kW.h): First Block		11.515	11.964	
	Balance	7.222	7.504	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	20.820	21.632	
Basic Charge (\$/month):		73.00	75.85	Based on 2024 Billing.

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	39	2.49	1,392	0.14	48.11	3.9	3.9	3.9
5000 to 10000	- 2	65	4.14	5,950	0.59	79.59	3.9	3.9	3.9
10000 to 15000	- 3	78	4.97	12,010	1.19	92.74	3.9	3.9	3.9
15000 to 20000	- 4	142	9.05	30,208	3.00	108.69	3.9	3.9	3.9
20000 to 25000	- 5	160	10.20	43,387	4.31	126.67	3.9	3.9	3.9
25000 to 30000	- 6	154	9.82	50,754	5.04	146.28	3.9	3.9	3.9
30000 to 35000	- 7	158	10.07	61,404	6.10	167.10	3.9	3.9	3.9
35000 to 40000	- 8	117	7.46	52,515	5.22	183.67	3.9	3.9	3.9
40000 to 45000	- 9	91	5.80	46,209	4.59	205.08	3.9	3.9	3.9
45000 to 50000	- 10	80	5.10	45,420	4.51	231.64	3.9	3.9	3.9
50000 to 55000	- 11	51	3.25	32,161	3.19	282.34	3.9	3.9	3.9
55000 to 60000	- 12	34	2.17	23,479	2.33	301.80	3.9	3.9	3.9
60000 to 65000	- 13	39	2.49	29,187	2.90	309.06	3.9	3.9	3.9
65000 to 70000	- 14	38	2.42	30,825	3.06	344.85	3.9	3.9	3.9
70000 to 75000	- 15	32	2.04	27,829	2.76	384.49	3.9	3.9	3.9
75000 to 80000	- 16	18	1.15	16,689	1.66	381.05	3.9	3.9	3.9
80000 to 85000	- 17	22	1.40	21,777	2.16	395.47	3.9	3.9	3.9
85000 to 90000	- 18	20	1.27	20,881	2.07	404.06	3.9	3.9	3.9
90000 to 95000	- 19	20	1.27	22,160	2.20	461.15	3.9	3.9	3.9
95000 to 100000	- 20	18	1.15	20,990	2.09	446.79	3.9	3.9	3.9
100000 to 125000	- 21	74	4.72	99,057	9.84	534.09	3.9	3.9	3.9
125000 to 150000	- 22	38	2.42	62,112	6.17	650.52	3.9	3.9	3.9
150000 to 175000	- 23	18	1.15	34,755	3.45	752.17	3.9	3.9	3.9
175000 to 200000	- 24	15	0.96	33,700	3.35	886.78	3.9	3.9	3.9
200000 to 250000	- 25	16	1.02	41,655	4.14	996.14	3.9	3.9	3.9
250000 to 300000	- 26	12	0.76	39,012	3.88	1,228.11	3.9	3.9	3.9
300000 to 400000	- 27	13	0.83	53,112	5.28	1,564.67	3.9	3.9	3.9
> 400000	- 28	7	0.45	47,991	4.77	2,563.60	3.9	3.9	3.9

Total		1,569	100.00	1,006,617	100.00	268.11	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E06 by Energy Intervals
General Service - Large
Rural - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		15,500	15,500	
Energy Rate (cents/kW.h): First Block		11.515	11.964	
	Balance	7.222	7.504	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	20.820	21.632	
Basic Charge (\$/month):		73.00	75.85	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	30	5.03	1,232	0.26	41.19	3.9	3.9	3.9
5000 to 10000	- 2	50	8.38	4,441	0.94	73.84	3.9	3.9	3.9
10000 to 15000	- 3	38	6.37	5,605	1.18	101.14	3.9	3.9	3.9
15000 to 20000	- 4	36	6.03	7,501	1.58	133.30	3.9	3.9	3.9
20000 to 25000	- 5	52	8.71	14,193	3.00	140.87	3.9	3.9	3.9
25000 to 30000	- 6	48	8.04	15,784	3.34	156.17	3.9	3.9	3.9
30000 to 35000	- 7	50	8.38	19,359	4.09	182.71	3.9	3.9	3.9
35000 to 40000	- 8	42	7.04	18,747	3.96	202.33	3.9	3.9	3.9
40000 to 45000	- 9	24	4.02	12,367	2.61	264.04	3.9	3.9	3.9
45000 to 50000	- 10	20	3.35	11,427	2.41	313.61	3.9	3.9	3.9
50000 to 55000	- 11	15	2.51	9,347	1.98	323.09	3.9	3.9	3.9
55000 to 60000	- 12	26	4.36	17,977	3.80	410.23	3.9	3.9	3.9
60000 to 65000	- 13	12	2.01	8,997	1.90	358.00	3.9	3.9	3.9
65000 to 70000	- 14	12	2.01	9,756	2.06	461.82	3.9	3.9	3.9
70000 to 75000	- 15	9	1.51	7,787	1.65	390.95	3.9	3.9	3.9
75000 to 80000	- 16	18	3.02	16,819	3.55	437.57	3.9	3.9	3.9
80000 to 85000	- 17	15	2.51	14,807	3.13	462.00	3.9	3.9	3.9
85000 to 90000	- 18	8	1.34	8,409	1.78	536.85	3.9	3.9	3.9
90000 to 95000	- 19	8	1.34	8,813	1.86	514.99	3.9	3.9	3.9
95000 to 100000	- 20	2	0.34	2,336	0.49	1,057.35	3.9	3.9	3.9
100000 to 125000	- 21	22	3.69	28,816	6.09	569.64	3.9	3.9	3.9
125000 to 150000	- 22	10	1.68	16,244	3.43	673.94	3.9	3.9	3.9
150000 to 175000	- 23	8	1.34	15,300	3.23	881.54	3.9	3.9	3.9
175000 to 200000	- 24	7	1.17	15,433	3.26	842.56	3.9	3.9	3.9
200000 to 250000	- 25	10	1.68	26,804	5.66	1,058.49	3.9	3.9	3.9
250000 to 300000	- 26	5	0.84	16,578	3.50	1,359.79	3.9	3.9	3.9
300000 to 400000	- 27	5	0.84	20,502	4.33	1,606.10	3.9	3.9	3.9
> 400000	- 28	15	2.51	117,877	24.91	2,844.88	3.9	3.9	3.9

Total		597	100.00	473,257	100.00	357.03	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E07 by Energy Intervals
General Service - Large
Urban - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.014	7.288	
Demand Rate (\$/kVA):	19.285	20.037	Based on Rate Class 3.9%
Basic Charge (\$/month):	278.68	289.55	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 50000	-	1	6	17.14	2,523	3.93	191.22	3.9	3.9	3.9
50000 to 100000	-	2	12	34.29	9,262	14.44	367.13	3.9	3.9	3.9
100000 to 200000	-	3	8	22.86	14,248	22.21	714.87	3.9	3.9	3.9
200000 to 300000	-	4	6	17.14	16,973	26.46	1,092.51	3.9	3.9	3.9
300000 to 400000	-	5	1	2.86	4,369	6.81	1,642.31	3.9	3.9	3.9
> 400000	-	6	2	5.71	16,770	26.14	3,027.94	3.9	3.9	3.9

Total			35	100.00	64,147	100.00	729.29	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E08 by Energy Intervals
General Service - Large
Rural - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.014	7.288	
Demand Rate (\$/kVA):	19.285	20.037	Based on Rate Class 3.9%
Basic Charge (\$/month):	278.68	289.55	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 50000	- 1	2	20.00	774	4.22	332.08	3.9	3.9	3.9
50000 to 100000	- 2	4	40.00	3,333	18.20	444.11	3.9	3.9	3.9
100000 to 200000	- 3	1	10.00	1,646	8.99	584.56	3.9	3.9	3.9
200000 to 300000	- 4	1	10.00	3,446	18.82	1,159.64	3.9	3.9	3.9
300000 to 400000	- 5	1	10.00	3,916	21.38	1,676.67	3.9	3.9	3.9
> 400000	- 6	1	10.00	5,199	28.39	1,895.77	3.9	3.9	3.9
Total		10	100.00	18,314	100.00	775.73	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E10 by Energy Intervals
General Service - Large
Customer Owned Transformation - 72kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	5.464	5.677	
Demand Rate (\$/kVA):	14.920	15.502	Based on Rate Class 3.9%
Basic Charge (\$/month):	288.26	299.50	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 200000	-	1	2	40.00	1,695	11.53	288.90	3.9	3.9	3.9
200000 to 400000	-	2	3	60.00	13,011	88.47	1,514.34	3.9	3.9	3.9
400000 to 600000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 600000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			5	100.00	14,706	100.00	1,024.16	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E12 by Energy Intervals
General Service - Large
Customer Owned Transformation - 138kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	5.328	5.536	
Demand Rate (\$/kVA):	14.455	15.019	Based on Rate Class 3.9%
Basic Charge (\$/month):	327.57	340.35	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 200000	-	1	1	50.00	343	3.17	160.31	3.9	3.9	3.9
200000 to 400000	-	2	-	0.00	-	0.00	0.00	0.0	0.0	0.0
400000 to 600000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 600000	-	4	1	50.00	10,466	96.83	3,108.32	3.9	3.9	3.9
Total			2	100.00	10,809	100.00	1,634.32	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E75 by Energy Intervals
General Service - Small Commercial
Urban - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		14,500	14,500	
Energy Rate (cents/kW.h): First Block		15.016	15.602	
	Balance	6.153	6.393	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	20.008	20.788	
Basic Charge (\$/month):		41.18	42.79	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000	-	1	18,475	64.73	159,175	17.31	5.82	3.9	3.9	3.9
2000 to 4000	-	2	4,494	15.75	153,107	16.65	18.27	3.9	3.9	3.9
4000 to 6000	-	3	2,006	7.03	118,404	12.88	30.48	3.9	3.9	3.9
6000 to 8000	-	4	1,153	4.04	95,505	10.39	42.11	3.9	3.9	3.9
8000 to 10000	-	5	735	2.58	78,710	8.56	53.96	3.9	3.9	3.9
10000 to 12000	-	6	460	1.61	60,375	6.57	65.68	3.9	3.9	3.9
12000 to 14000	-	7	334	1.17	52,119	5.67	77.09	3.9	3.9	3.9
14000 to 16000	-	8	246	0.86	44,088	4.79	86.51	3.9	3.9	3.9
16000 to 18000	-	9	211	0.74	42,892	4.66	93.94	3.9	3.9	3.9
18000 to 20000	-	10	143	0.50	32,575	3.54	100.20	3.9	3.9	3.9
> 20000	-	11	285	1.00	82,674	8.99	116.02	3.9	3.9	3.9
Total			28,542	100.00	919,624	100.00	16.94	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E76 by Energy Intervals
General Service - Small Commercial
Rural - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		13,000	13,000	
Energy Rate (cents/kW.h): First Block		15.016	15.602	
	Balance	6.153	6.393	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	20.008	20.788	
Basic Charge (\$/month):		41.18	42.79	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000	-	1	4,747	63.10	46,385	19.92	0.53	3.9	3.9	3.9
2000 to 4000	-	2	1,362	18.10	46,632	20.02	1.53	3.9	3.9	3.9
4000 to 6000	-	3	620	8.24	36,533	15.69	2.52	3.9	3.9	3.9
6000 to 8000	-	4	281	3.74	23,202	9.96	3.46	3.9	3.9	3.9
8000 to 10000	-	5	160	2.13	17,132	7.36	4.40	3.9	3.9	3.9
10000 to 12000	-	6	118	1.57	15,594	6.70	5.34	3.9	3.9	3.9
12000 to 14000	-	7	79	1.05	12,231	5.25	6.06	3.9	3.9	3.9
14000 to 16000	-	8	53	0.70	9,535	4.09	6.68	3.9	3.9	3.9
16000 to 18000	-	9	32	0.43	6,567	2.82	7.19	3.9	3.9	3.9
18000 to 20000	-	10	25	0.33	5,657	2.43	7.71	3.9	3.9	3.9
> 20000	-	11	46	0.61	13,410	5.76	8.93	3.9	3.9	3.9
Total			7,523	100.00	232,876	100.00	1.35	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E77 by Energy Intervals
General Service - Small Commercial
Urban - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		14,500	14,500	
Energy Rate (cents/kW.h): First Block		15.016	15.602	
	Balance	6.153	6.393	Based on Rate Class
Demand Rate (\$/kVA):	First 50kVA	0	0	3.9%
	Balance	19.308	20.061	
Basic Charge (\$/month):		41.18	42.79	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	16	64.00	221	16.98	8.34	3.9	3.9	3.9
5000 to 10000	- 2	6	24.00	464	35.72	39.38	3.9	3.9	3.9
10000 to 15000	- 3	1	4.00	121	9.31	60.66	3.9	3.9	3.9
> 15000	- 4	2	8.00	493	37.98	106.80	3.9	3.9	3.9
Total		25	100.00	1,299	100.00	25.76	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E78 by Energy Intervals
General Service - Small Commercial
Rural - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		13,000	13,000	
Energy Rate (cents/kW.h): First Block		15.016	15.602	
	Balance	6.153	6.393	Based on Rate Class
Demand Rate (\$/kVA):	First 50kVA	0	0	3.9%
	Balance	19.308	20.061	
Basic Charge (\$/month):		41.18	42.79	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	-	1	11	78.57	178	42.80	10.51	3.9	3.9	3.9
5000 to 10000	-	2	3	21.43	238	57.20	40.42	3.9	3.9	3.9
10000 to 15000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 15000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			14	100.00	417	100.00	16.92	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E43 by Energy Intervals
Oilfields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.171	7.451	
Demand Rate (\$/kVA):	17.796	18.490	Based on Rate Class 3.9%
Basic Charge (\$/month):	78.57	81.63	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 1000	- 1	1,991	14.42	7,137	0.24	5.20	3.9	3.9	3.9
1000 to 2000	- 2	886	6.42	15,991	0.55	11.91	3.9	3.9	3.9
2000 to 3000	- 3	916	6.63	27,611	0.94	16.35	3.9	3.9	3.9
3000 to 4000	- 4	850	6.16	35,539	1.21	20.32	3.9	3.9	3.9
4000 to 5000	- 5	840	6.08	45,151	1.54	24.32	3.9	3.9	3.9
5000 to 6000	- 6	727	5.27	47,801	1.63	28.64	3.9	3.9	3.9
6000 to 7000	- 7	656	4.75	51,059	1.74	32.83	3.9	3.9	3.9
7000 to 8000	- 8	554	4.01	49,651	1.69	36.91	3.9	3.9	3.9
8000 to 9000	- 9	511	3.70	52,144	1.78	41.11	3.9	3.9	3.9
9000 to 10000	- 10	467	3.38	53,105	1.81	45.18	3.9	3.9	3.9
10000 to 15000	- 11	1,653	11.97	243,701	8.32	57.72	3.9	3.9	3.9
15000 to 20000	- 12	947	6.86	196,570	6.71	76.60	3.9	3.9	3.9
20000 to 25000	- 13	657	4.76	175,716	6.00	96.60	3.9	3.9	3.9
25000 to 30000	- 14	448	3.24	147,201	5.02	118.08	3.9	3.9	3.9
30000 to 40000	- 15	534	3.87	221,839	7.57	146.92	3.9	3.9	3.9
40000 to 50000	- 16	302	2.19	161,524	5.51	187.91	3.9	3.9	3.9
50000 to 75000	- 17	376	2.72	272,681	9.31	252.12	3.9	3.9	3.9
75000 to 100000	- 18	155	1.12	160,404	5.47	361.05	3.9	3.9	3.9
100000 to 200000	- 19	206	1.49	339,008	11.57	567.30	3.9	3.9	3.9
> 200000	- 20	130	0.94	625,921	21.36	1,621.95	3.9	3.9	3.9
Total		13,806	100.00	2,929,754	100.00	77.97	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E44 by Energy Intervals
Oilfields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.171	7.451	
Demand Rate (\$/kVA):	17.096	17.763	Based on Rate Class 3.9%
Basic Charge (\$/month):	78.57	81.63	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
100000 to 200000	- 1	2	28.57	3,408	10.97	628.50	3.9	3.9	3.9
200000 to 300000	- 2	1	14.29	2,923	9.41	935.37	3.9	3.9	3.9
>300000	- 3	4	57.14	24,727	79.62	2,144.67	3.9	3.9	3.9
Total		7	100.00	31,058	100.00	1,538.72	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E46 by Energy Intervals
Power - Oilfield
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.253	6.497	
Demand Rate (\$/kVA):	17.998	18.700	Based on Rate Class 3.9%
Basic Charge (\$/month):	6,759.21	7,022.82	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	22	70.97	191,781	38.73	2,935.47	3.9	3.9	3.9
2000000 to 5000000	-	2	9	29.03	303,406	61.27	10,382.74	3.9	3.9	3.9
5000000 to 20000000	-	3	0	0.00	-	0.00	0.00	0.0	0.0	0.0
> 20000000	-	4	0	0.00	-	0.00	0.00	0.0	0.0	0.0

Total			31	100.00	495,187	100.00	5,097.58	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E47 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.208	6.450	Based on Rate Class
Demand Rate (\$/kVA):	14.632	15.203	3.9%
Basic Charge (\$/month):	7,845.52	8,151.50	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
5000000 to 20000000	- 1	1	100.00	78,659	100.00	21,910.57	3.9	3.9	3.9
Total		1	100.00	78,659	100.00	21,910.57	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E48 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.025	6.260	
Demand Rate (\$/kVA):	11.586	12.038	Based on Rate Class 3.9%
Basic Charge (\$/month):	8,403.75	8,731.50	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
2000000-5000000	-	1	1	50.00	24,658	6.94	6,745.02	3.9	3.9	3.9
> 20000000	-	2	1	50.00	330,451	93.06	83,676.99	3.9	3.9	3.9
Total			2	100.00	355,109	100.00	45,211.01	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E22 by Energy Intervals
Power
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.253	6.497	
Demand Rate (\$/kVA):	17.998	18.700	Based on Rate Class 3.9%
Basic Charge (\$/month):	6,759.21	7,022.82	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	24	85.71	244,113	64.02	3,751.86	3.9	3.9	3.9
2000000 to 5000000	-	2	4	14.29	137,208	35.98	11,612.88	3.9	3.9	3.9
Total			28	100.00	381,322	100.00	4,874.86	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E23 by Energy Intervals
Power
Customer Owned Transformation - 72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.208	6.450	Based on Rate Class
Demand Rate (\$/kVA):	14.632	15.203	3.9%
Basic Charge (\$/month):	7,845.52	8,151.50	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	9	52.94	135,965	22.08	5,155.63	3.9	3.9	3.9
2000000 to 5000000	-	2	5	29.41	213,364	34.64	13,203.64	3.9	3.9	3.9
5000000 to 20000000	-	3	3	17.65	266,557	43.28	26,009.68	3.9	3.9	3.9
> 20000000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0

Total			17	100.00	615,886	100.00	11,202.82	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E24 by Energy Intervals
Power
Customer Owned Transformation - 138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.025	6.260	Based on Rate Class
Demand Rate (\$/kVA):	11.586	12.038	3.9%
Basic Charge (\$/month):	8,403.75	8,731.50	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	7	17.07	44,280	1.11	2,645.28	3.9	3.9	3.9
2000000 to 5000000	-	2	18	43.90	838,228	21.03	13,078.08	3.9	3.9	3.9
5000000 to 20000000	-	3	11	26.83	1,253,662	31.45	30,653.11	3.9	3.9	3.9
> 20000000	-	4	5	12.20	1,849,739	46.41	97,377.65	3.9	3.9	3.9
Total			41	100.00	3,985,909	100.00	26,292.56	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2025-26
Rate Change Impacts on E84 by Energy Intervals
Power - Time of Use
Customer Owned Transformation - 100kV & Above

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.597	6.833	
Energy Off Peak Rate (cents/kW.h):	5.597	5.833	Based on Rate Class
Demand Rate (\$/kVA):	11.586	12.038	3.9%
Basic Charge (\$/month):	8,403.75	8,731.50	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
> 20000000	- 1	6	100.00	1,887,253	100.00	85,422.68	3.9	3.9	3.9
Total		6	100.00	1,887,253	100.00	85,422.68	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E01 by Energy Intervals
Urban Residential

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	15.476	16.079	3.9%
Basic Charge: (\$/month)	31.16	32.37	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	-	1	4,864	1.98	3,508	0.19	1.58	3.9	3.9	3.9
100 to 200	-	2	15,300	6.22	28,792	1.55	2.16	3.9	3.9	3.9
200 to 300	-	3	25,056	10.18	75,862	4.09	2.74	3.9	3.9	3.9
300 to 400	-	4	29,604	12.03	124,690	6.72	3.33	3.9	3.9	3.9
400 to 500	-	5	32,473	13.20	175,396	9.45	4.16	3.9	3.9	3.9
500 to 600	-	6	31,537	12.82	207,809	11.20	4.53	3.9	3.9	3.9
600 to 700	-	7	26,583	10.81	206,890	11.15	5.13	3.9	3.9	3.9
700 to 800	-	8	21,170	8.61	189,973	10.24	5.73	3.9	3.9	3.9
800 to 900	-	9	16,032	6.52	163,041	8.79	6.33	3.9	3.9	3.9
900 to 1000	-	10	11,778	4.79	133,855	7.21	6.93	3.9	3.9	3.9
1000 to 1100	-	11	8,488	3.45	106,692	5.75	7.54	3.9	3.9	3.9
1100 to 1200	-	12	6,169	2.51	84,972	4.58	8.14	3.9	3.9	3.9
1200 to 1300	-	13	4,321	1.76	64,655	3.48	8.74	3.9	3.9	3.9
1300 to 1400	-	14	3,081	1.25	49,826	2.69	9.35	3.9	3.9	3.9
1400 to 1500	-	15	2,246	0.91	38,978	2.10	9.94	3.9	3.9	3.9
1500 to 2000	-	16	5,024	2.04	102,332	5.52	11.46	3.9	3.9	3.9
2000 to 2500	-	17	1,384	0.56	36,603	1.97	14.52	3.9	3.9	3.9
2500 to 3000	-	18	467	0.19	15,175	0.82	17.56	3.9	3.9	3.9
3000 to 3500	-	19	165	0.07	6,349	0.34	20.57	3.9	3.9	3.9
3500 to 4000	-	20	87	0.04	3,879	0.21	23.64	3.9	3.9	3.9
4000 to 4500	-	21	27	0.01	1,362	0.07	26.59	3.9	3.9	3.9
4500 to 5000	-	22	10	0.00	559	0.03	29.34	3.9	3.9	3.9
5000 to 6000	-	23	17	0.01	1,095	0.06	33.62	3.9	3.9	3.9
6000 to 7000	-	24	19	0.01	1,475	0.08	40.27	3.9	3.9	3.9
7000 to 8000	-	25	12	0.00	1,082	0.06	46.58	3.9	3.9	3.9
8000 to 9000	-	26	7	0.00	723	0.04	53.17	3.9	3.9	3.9
9000 to 10000	-	27	5	0.00	572	0.03	58.73	3.9	3.9	3.9
> 10000	-	28	83	0.03	29,276	1.58	178.62	3.9	3.9	3.9
Total			246,009	100.00	1,855,424	100.00	5.04	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E03 by Energy Intervals
Rural Residential

Rate Breakdown	Existing	Proposed	Based on Rate Class
Energy Rate: (cents/kW.h)	15.476	16.079	3.9%
Basic Charge: (\$/month)	31.16	32.37	Based on 2024 Billing.

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	-	1	1,435	2.55	948	0.12	1.55	3.9	3.9
100 to 200	-	2	1,709	3.04	3,102	0.41	2.13	3.9	3.9
200 to 300	-	3	2,008	3.57	6,060	0.79	2.73	3.9	3.9
300 to 400	-	4	2,531	4.50	10,722	1.40	3.35	3.9	3.9
400 to 500	-	5	3,240	5.76	17,541	2.30	3.94	3.9	3.9
500 to 600	-	6	3,630	6.45	23,996	3.14	4.54	3.9	3.9
600 to 700	-	7	4,015	7.13	31,359	4.10	5.14	3.9	3.9
700 to 800	-	8	4,001	7.11	35,965	4.71	5.74	3.9	3.9
800 to 900	-	9	3,799	6.75	38,707	5.07	6.34	3.9	3.9
900 to 1000	-	10	3,547	6.30	40,401	5.29	6.94	3.9	3.9
1000 to 1100	-	11	3,205	5.69	40,310	5.28	7.54	3.9	3.9
1100 to 1200	-	12	2,904	5.16	40,020	5.24	8.14	3.9	3.9
1200 to 1300	-	13	2,518	4.47	37,745	4.94	8.75	3.9	3.9
1300 to 1400	-	14	2,233	3.97	36,142	4.73	9.35	3.9	3.9
1400 to 1500	-	15	1,935	3.44	33,621	4.40	9.95	3.9	3.9
1500 to 2000	-	16	6,613	11.75	136,915	17.92	11.62	3.9	3.9
2000 to 2500	-	17	3,467	6.16	92,574	12.12	14.63	3.9	3.9
2500 to 3000	-	18	1,762	3.13	57,614	7.54	17.63	3.9	3.9
3000 to 3500	-	19	922	1.64	35,623	4.66	20.59	3.9	3.9
3500 to 4000	-	20	388	0.69	17,314	2.27	23.51	3.9	3.9
4000 to 4500	-	21	187	0.33	9,451	1.24	26.32	3.9	3.9
4500 to 5000	-	22	99	0.18	5,588	0.73	29.04	3.9	3.9
5000 to 6000	-	23	84	0.15	5,413	0.71	32.28	3.9	3.9
6000 to 7000	-	24	26	0.05	2,008	0.26	36.15	3.9	3.9
7000 to 8000	-	25	15	0.03	1,329	0.17	39.30	3.9	3.9
8000 to 9000	-	26	4	0.01	409	0.05	40.31	3.9	3.9
9000 to 10000	-	27	4	0.01	447	0.06	41.51	3.9	3.9
> 10000	-	28	14	0.02	2,732	0.36	44.40	3.9	3.9
Total		56,295	100.00	764,057	100.00	8.01	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E04 by Energy Intervals
Rural Residential - Residential Diesel

Rate Breakdown	Existing	Proposed	Based on Rate Class
First Block Size (kW.h/month)	650	650	3.9%
Energy Rate (cents/kW.h): First Block	15.476	16.079	
Balance	60.416	62.772	
Basic Charge: (\$/month)	31.16	32.37	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 300	-	1	3	50.00	6	18.43	5.46	3.9	3.9	3.9
300 to 400	-	2	-	0.00	-	0.00	0.00	0.0	0.0	0.0
400 to 900	-	3	2	33.33	18	49.85	16.21	3.9	3.9	3.9
900 to 1000	-	4	1	16.67	11	31.73	18.23	3.9	3.9	3.9
> 1000	-	5	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			6	100.00	35	100.00	11.17	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E34 by Energy Intervals
Farm

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		16,000	16,000	
Energy Rate (cents/kW.h): First Block		13.852	14.392	
	Balance	5.820	6.047	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	15.727	16.341	
Basic Charge (\$/month):		48.02	49.90	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 100	-	1	2,651	6.43	1,246	0.12	2.08	3.9	3.9
100 to 200	-	2	1,470	3.56	2,636	0.26	2.68	3.9	3.9
200 to 300	-	3	1,287	3.12	3,827	0.38	3.21	3.9	3.9
300 to 400	-	4	1,314	3.19	5,522	0.55	3.76	3.9	3.9
400 to 500	-	5	1,338	3.24	7,242	0.72	4.31	3.9	3.9
500 to 600	-	6	1,477	3.58	9,769	0.97	4.85	3.9	3.9
600 to 700	-	7	1,646	3.99	12,827	1.27	5.38	3.9	3.9
700 to 800	-	8	1,674	4.06	15,094	1.50	5.93	3.9	3.9
800 to 900	-	9	1,747	4.24	17,822	1.77	6.47	3.9	3.9
900 to 1000	-	10	1,627	3.95	18,542	1.84	7.01	3.9	3.9
1000 to 1100	-	11	1,644	3.99	20,716	2.05	7.55	3.9	3.9
1100 to 1200	-	12	1,553	3.77	21,424	2.12	8.09	3.9	3.9
1200 to 1300	-	13	1,453	3.52	21,790	2.16	8.63	3.9	3.9
1300 to 1400	-	14	1,428	3.46	23,121	2.29	9.16	3.9	3.9
1400 to 1500	-	15	1,261	3.06	21,935	2.17	9.71	3.9	3.9
1500 to 1600	-	16	1,276	3.09	23,746	2.35	10.26	3.9	3.9
1600 to 1700	-	17	1,115	2.70	22,069	2.19	10.79	3.9	3.9
1700 to 1800	-	18	1,066	2.58	22,380	2.22	11.34	3.9	3.9
1800 to 1900	-	19	1,000	2.42	22,186	2.20	11.86	3.9	3.9
1900 to 2000	-	20	979	2.37	22,893	2.27	12.42	3.9	3.9
2000 to 2500	-	21	3,798	9.21	101,980	10.11	13.98	3.9	3.9
2500 to 3000	-	22	2,601	6.31	85,280	8.45	16.70	3.9	3.9
3000 to 3500	-	23	1,771	4.29	68,619	6.80	19.36	3.9	3.9
3500 to 4000	-	24	1,122	2.72	50,291	4.98	22.15	3.9	3.9
4000 to 4500	-	25	745	1.81	37,838	3.75	24.84	3.9	3.9
4500 to 5000	-	26	534	1.29	30,379	3.01	27.63	3.9	3.9
5000 to 10000	-	27	1,185	2.87	90,939	9.01	36.90	3.9	3.9
10000 to 15000	-	28	147	0.36	21,415	2.12	69.40	3.9	3.9
15000 to 20000	-	29	64	0.16	13,149	1.30	96.00	3.9	3.9
20000 to 25000	-	30	38	0.09	10,343	1.03	120.70	3.9	3.9
> 25000	-	31	227	0.55	181,849	18.03	277.44	3.9	3.9
Total		41,238	100.00	1,008,869	100.00	12.46	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E05 by Energy Intervals
General Service - Large
Urban - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		16,750	16,750	
Energy Rate (cents/kW.h): First Block		11.964	12.431	
	Balance	7.504	7.796	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	21.632	22.476	
Basic Charge (\$/month):		75.85	78.81	Based on 2024 Billing.

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	39	2.49	1,392	0.14	49.98	3.9	3.9	3.9
5000 to 10000	- 2	65	4.14	5,950	0.59	82.69	3.9	3.9	3.9
10000 to 15000	- 3	78	4.97	12,010	1.19	96.36	3.9	3.9	3.9
15000 to 20000	- 4	142	9.05	30,208	3.00	112.93	3.9	3.9	3.9
20000 to 25000	- 5	160	10.20	43,387	4.31	131.60	3.9	3.9	3.9
25000 to 30000	- 6	154	9.82	50,754	5.04	151.96	3.9	3.9	3.9
30000 to 35000	- 7	158	10.07	61,404	6.10	173.57	3.9	3.9	3.9
35000 to 40000	- 8	117	7.46	52,515	5.22	190.77	3.9	3.9	3.9
40000 to 45000	- 9	91	5.80	46,209	4.59	212.99	3.9	3.9	3.9
45000 to 50000	- 10	80	5.10	45,420	4.51	240.57	3.9	3.9	3.9
50000 to 55000	- 11	51	3.25	32,161	3.19	293.23	3.9	3.9	3.9
55000 to 60000	- 12	34	2.17	23,479	2.33	313.44	3.9	3.9	3.9
60000 to 65000	- 13	39	2.49	29,187	2.90	320.96	3.9	3.9	3.9
65000 to 70000	- 14	38	2.42	30,825	3.06	358.13	3.9	3.9	3.9
70000 to 75000	- 15	32	2.04	27,829	2.76	399.30	3.9	3.9	3.9
75000 to 80000	- 16	18	1.15	16,689	1.66	395.70	3.9	3.9	3.9
80000 to 85000	- 17	22	1.40	21,777	2.16	410.66	3.9	3.9	3.9
85000 to 90000	- 18	20	1.27	20,881	2.07	419.58	3.9	3.9	3.9
90000 to 95000	- 19	20	1.27	22,160	2.20	478.87	3.9	3.9	3.9
95000 to 100000	- 20	18	1.15	20,990	2.09	463.94	3.9	3.9	3.9
100000 to 125000	- 21	74	4.72	99,057	9.84	554.59	3.9	3.9	3.9
125000 to 150000	- 22	38	2.42	62,112	6.17	675.47	3.9	3.9	3.9
150000 to 175000	- 23	18	1.15	34,755	3.45	781.00	3.9	3.9	3.9
175000 to 200000	- 24	15	0.96	33,700	3.35	920.77	3.9	3.9	3.9
200000 to 250000	- 25	16	1.02	41,655	4.14	1,034.28	3.9	3.9	3.9
250000 to 300000	- 26	12	0.76	39,012	3.88	1,275.11	3.9	3.9	3.9
300000 to 400000	- 27	13	0.83	18,742	1.86	563.64	3.9	3.9	3.9
> 400000	- 28	7	0.45	82,360	8.18	4,631.85	3.9	3.9	3.9

Total		1,569	100.00	1,006,617	100.00	278.44	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E06 by Energy Intervals
General Service - Large
Rural - SaskPower Supplied Transformation (Over 75 kVA)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		15,500	15,500	
Energy Rate (cents/kW.h): First Block		11.964	12.431	
	Balance	7.504	7.796	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	21.632	22.476	
Basic Charge (\$/month):		75.85	78.81	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	30	5.03	1,232	0.26	42.79	3.9	3.9	3.9
5000 to 10000	- 2	50	8.38	4,441	0.94	76.72	3.9	3.9	3.9
10000 to 15000	- 3	38	6.37	5,605	1.18	105.09	3.9	3.9	3.9
15000 to 20000	- 4	36	6.03	7,501	1.58	138.49	3.9	3.9	3.9
20000 to 25000	- 5	52	8.71	14,193	3.00	146.34	3.9	3.9	3.9
25000 to 30000	- 6	48	8.04	15,784	3.34	162.22	3.9	3.9	3.9
30000 to 35000	- 7	50	8.38	19,359	4.09	189.79	3.9	3.9	3.9
35000 to 40000	- 8	42	7.04	18,747	3.96	210.15	3.9	3.9	3.9
40000 to 45000	- 9	24	4.02	12,367	2.61	274.25	3.9	3.9	3.9
45000 to 50000	- 10	20	3.35	11,427	2.41	325.73	3.9	3.9	3.9
50000 to 55000	- 11	15	2.51	9,347	1.98	335.57	3.9	3.9	3.9
55000 to 60000	- 12	26	4.36	17,977	3.80	426.09	3.9	3.9	3.9
60000 to 65000	- 13	12	2.01	8,997	1.90	371.81	3.9	3.9	3.9
65000 to 70000	- 14	12	2.01	9,756	2.06	479.65	3.9	3.9	3.9
70000 to 75000	- 15	9	1.51	7,787	1.65	406.00	3.9	3.9	3.9
75000 to 80000	- 16	18	3.02	16,819	3.55	454.42	3.9	3.9	3.9
80000 to 85000	- 17	15	2.51	14,807	3.13	479.79	3.9	3.9	3.9
85000 to 90000	- 18	8	1.34	8,409	1.78	557.54	3.9	3.9	3.9
90000 to 95000	- 19	8	1.34	8,813	1.86	534.81	3.9	3.9	3.9
95000 to 100000	- 20	2	0.34	2,336	0.49	1,098.29	3.9	3.9	3.9
100000 to 125000	- 21	22	3.69	28,816	6.09	591.52	3.9	3.9	3.9
125000 to 150000	- 22	10	1.68	16,244	3.43	699.80	3.9	3.9	3.9
150000 to 175000	- 23	8	1.34	15,300	3.23	915.41	3.9	3.9	3.9
175000 to 200000	- 24	7	1.17	15,433	3.26	874.82	3.9	3.9	3.9
200000 to 250000	- 25	10	1.68	26,804	5.66	1,099.03	3.9	3.9	3.9
250000 to 300000	- 26	5	0.84	16,578	3.50	1,411.89	3.9	3.9	3.9
300000 to 400000	- 27	5	0.84	20,502	4.33	1,667.57	3.9	3.9	3.9
> 400000	- 28	15	2.51	117,877	24.91	2,953.54	3.9	3.9	3.9

Total		597	100.00	473,257	100.00	370.77	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E07 by Energy Intervals
General Service - Large
Urban - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.288	7.572	
Demand Rate (\$/kVA):	20.037	20.819	Based on Rate Class 3.9%
Basic Charge (\$/month):	289.55	300.84	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 50000	-	1	6	17.14	2,523	3.93	198.53	3.9	3.9	3.9
50000 to 100000	-	2	12	34.29	9,262	14.44	381.18	3.9	3.9	3.9
100000 to 200000	-	3	8	22.86	14,248	22.21	742.10	3.9	3.9	3.9
200000 to 300000	-	4	6	17.14	16,973	26.46	1,134.08	3.9	3.9	3.9
300000 to 400000	-	5	1	2.86	4,369	6.81	1,704.75	3.9	3.9	3.9
> 400000	-	6	2	5.71	16,770	26.14	3,142.91	3.9	3.9	3.9
Total			35	100.00	64,147	100.00	757.06	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E08 by Energy Intervals
General Service - Large
Rural - Customer Owned Transformation - 25kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.288	7.572	
Demand Rate (\$/kVA):	20.037	20.819	Based on Rate Class 3.9%
Basic Charge (\$/month):	289.55	300.84	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 50000	-	1	2	20.00	774	4.22	344.91	3.9	3.9	3.9
50000 to 100000	-	2	4	40.00	3,333	18.20	461.14	3.9	3.9	3.9
100000 to 200000	-	3	1	10.00	1,646	8.99	606.74	3.9	3.9	3.9
200000 to 300000		4	1	10.00	3,446	18.82	1,203.56	3.9	3.9	3.9
300000 to 400000	-	5	1	10.00	3,916	21.38	1,740.64	3.9	3.9	3.9
> 400000	-	6	1	10.00	5,199	28.39	1,967.77	3.9	3.9	3.9
Total			10	100.00	18,314	100.00	805.31	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E10 by Energy Intervals
General Service - Large
Customer Owned Transformation - 72kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	5.677	5.899	
Demand Rate (\$/kVA):	15.502	16.106	Based on Rate Class 3.9%
Basic Charge (\$/month):	299.50	311.18	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 200000	-	1	2	40.00	1,695	11.53	300.22	3.9	3.9	3.9
200000 to 400000	-	2	3	60.00	13,011	88.47	1,573.60	3.9	3.9	3.9
400000 to 600000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 600000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			5	100.00	14,706	100.00	1,064.25	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E12 by Energy Intervals
General Service - Large
Customer Owned Transformation - 138kV and Less (Over 75 kVA)

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	5.536	5.752	
Demand Rate (\$/kVA):	15.019	15.604	Based on Rate Class 3.9%
Basic Charge (\$/month):	340.35	353.62	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 200000	-	1	1	50.00	343	3.17	166.45	3.9	3.9	3.9
200000 to 400000	-	2	-	0.00	-	0.00	0.00	0.0	0.0	0.0
400000 to 600000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 600000	-	4	1	50.00	10,466	96.83	3,227.06	0.0	0.0	0.0
Total			2	100.00	10,809	100.00	1,696.75	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E75 by Energy Intervals
General Service - Small Commercial
Urban - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		14,500	14,500	
Energy Rate (cents/kW.h): First Block		15.602	16.210	
	Balance	6.393	6.642	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0.000	0.000	3.9%
	Balance	20.788	21.599	
Basic Charge (\$/month):		42.79	44.45	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000	- 1	18,475	64.73	159,175	17.31	6.04	3.9	3.9	3.9
2000 to 4000	- 2	4,494	15.75	153,107	16.65	18.97	3.9	3.9	3.9
4000 to 6000	- 3	2,006	7.03	118,404	12.88	31.64	3.9	3.9	3.9
6000 to 8000	- 4	1,153	4.04	95,505	10.39	43.72	3.9	3.9	3.9
8000 to 10000	- 5	735	2.58	78,710	8.56	56.03	3.9	3.9	3.9
10000 to 12000	- 6	460	1.61	60,375	6.57	68.19	3.9	3.9	3.9
12000 to 14000	- 7	334	1.17	52,119	5.67	80.05	3.9	3.9	3.9
14000 to 16000	- 8	246	0.86	44,088	4.79	89.83	3.9	3.9	3.9
16000 to 18000	- 9	211	0.74	42,892	4.66	97.55	3.9	3.9	3.9
18000 to 20000	- 10	143	0.50	32,575	3.54	104.04	3.9	3.9	3.9
> 20000	- 11	285	1.00	82,674	8.99	120.48	3.9	3.9	3.9
Total		28,542	100.00	919,624	100.00	17.59	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E76 by Energy Intervals
General Service - Small Commercial
Rural - SaskPower Supplied Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		13,000	13,000	
Energy Rate (cents/kW.h): First Block		15.602	16.210	
	Balance	6.393	6.642	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	20.788	21.599	
Basic Charge (\$/month):		42.79	44.45	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000	- 1	4,747	63.10	46,385	19.92	0.55	3.9	3.9	3.9
2000 to 4000	- 2	1,362	18.10	46,632	20.02	1.59	3.9	3.9	3.9
4000 to 6000	- 3	620	8.24	36,533	15.69	2.61	3.9	3.9	3.9
6000 to 8000	- 4	281	3.74	23,202	9.96	3.59	3.9	3.9	3.9
8000 to 10000	- 5	160	2.13	17,132	7.36	4.57	3.9	3.9	3.9
10000 to 12000	- 6	118	1.57	15,594	6.70	5.54	3.9	3.9	3.9
12000 to 14000	- 7	79	1.05	12,231	5.25	6.29	3.9	3.9	3.9
14000 to 16000	- 8	53	0.70	9,535	4.09	6.94	3.9	3.9	3.9
16000 to 18000	- 9	32	0.43	6,567	2.82	7.47	3.9	3.9	3.9
18000 to 20000	- 10	25	0.33	5,657	2.43	8.00	3.9	3.9	3.9
> 20000	- 11	46	0.61	13,410	5.76	9.27	3.9	3.9	3.9
Total		7,523	100.00	232,876	100.00	1.40	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E77 by Energy Intervals
General Service - Small Commercial
Urban - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		14,500	14,500	
Energy Rate (cents/kW.h): First Block		15.602	16.210	
	Balance	6.393	6.642	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	20.061	20.843	
Basic Charge (\$/month):		42.79	44.45	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	- 1	16	64.00	221	16.98	8.66	3.9	3.9	3.9
5000 to 10000	- 2	6	24.00	464	35.72	40.88	3.9	3.9	3.9
10000 to 15000	- 3	1	4.00	121	9.31	62.98	3.9	3.9	3.9
> 15000	- 4	2	8.00	493	37.98	110.90	3.9	3.9	3.9
Total		25	100.00	1,299	100.00	26.75	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E78 by Energy Intervals
General Service - Small Commercial
Rural - Customer Owned Transformation (75 kVA and Less)

Rate Breakdown		Existing	Proposed	
First Block Size (kW.h/month)		13,000	13,000	
Energy Rate (cents/kW.h): First Block		15.602	16.210	
	Balance	6.393	6.642	Based on Rate Class
Demand Rate (\$/kVA): First 50kVA		0	0	3.9%
	Balance	20.061	20.843	
Basic Charge (\$/month):		42.79	44.45	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 5000	-	1	11	78.57	178	42.80	10.91	3.9	3.9	3.9
5000 to 10000	-	2	3	21.43	238	57.20	41.96	3.9	3.9	3.9
10000 to 15000	-	3	-	0.00	-	0.00	0.00	0.0	0.0	0.0
> 15000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			14	100.00	417	100.00	17.57	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E43 by Energy Intervals
Oil Fields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.451	7.741	
Demand Rate (\$/kVA):	18.490	19.211	Based on Rate Class 3.9%
Basic Charge (\$/month):	81.63	84.82	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 1000	- 1	1,991	14.42	7,137	0.24	5.41	3.9	3.9	3.9
1000 to 2000	- 2	886	6.42	15,991	0.55	12.37	3.9	3.9	3.9
2000 to 3000	- 3	916	6.63	27,611	0.94	16.99	3.9	3.9	3.9
3000 to 4000	- 4	850	6.16	35,539	1.21	21.10	3.9	3.9	3.9
4000 to 5000	- 5	840	6.08	45,151	1.54	25.25	3.9	3.9	3.9
5000 to 6000	- 6	727	5.27	47,801	1.63	29.74	3.9	3.9	3.9
6000 to 7000	- 7	656	4.75	51,059	1.74	34.09	3.9	3.9	3.9
7000 to 8000	- 8	554	4.01	49,651	1.69	38.33	3.9	3.9	3.9
8000 to 9000	- 9	511	3.70	52,144	1.78	42.69	3.9	3.9	3.9
9000 to 10000	- 10	467	3.38	53,105	1.81	46.91	3.9	3.9	3.9
10000 to 15000	- 11	1,653	11.97	243,701	8.32	59.94	3.9	3.9	3.9
15000 to 20000	- 12	947	6.86	196,570	6.71	79.54	3.9	3.9	3.9
20000 to 25000	- 13	657	4.76	175,716	6.00	100.30	3.9	3.9	3.9
25000 to 30000	- 14	448	3.24	147,201	5.02	122.60	3.9	3.9	3.9
30000 to 40000	- 15	534	3.87	221,839	7.57	152.54	3.9	3.9	3.9
40000 to 50000	- 16	302	2.19	161,524	5.51	195.09	3.9	3.9	3.9
50000 to 75000	- 17	376	2.72	272,681	9.31	261.75	3.9	3.9	3.9
75000 to 100000	- 18	155	1.12	160,404	5.47	374.85	3.9	3.9	3.9
100000 to 200000	- 19	206	1.49	339,008	11.57	588.97	3.9	3.9	3.9
> 200000	- 20	130	0.94	625,921	21.36	1,683.86	3.9	3.9	3.9
Total		13,806	100.00	2,929,754	100.00	80.96	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E44 by Energy Intervals
Oil Fields

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	7.451	7.741	
Demand Rate (\$/kVA):	17.763	18.455	Based on Rate Class 3.9%
Basic Charge (\$/month):	81.63	84.82	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
100000 to 200000	-	1	2	28.57	3,408	10.97	653.01	3.9	3.9	3.9
200000 to 300000	-	2	1	14.29	2,923	9.41	971.85	3.9	3.9	3.9
>300000	-	3	4	57.14	24,727	79.62	2,228.31	3.9	3.9	3.9
Total			7	100.00	31,058	100.00	1,598.73	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E46 by Energy Intervals
Power - Oilfield
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.497	6.750	
Demand Rate (\$/kVA):	18.700	19.429	Based on Rate Class 3.9%
Basic Charge (\$/month):	7,022.82	7,296.71	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	22	70.97	191,781	38.73	3,048.84	3.9	3.9	3.9
2000000 to 5000000	-	2	9	29.03	303,406	61.27	10,783.41	3.9	3.9	3.9
5000000 to 20000000	-	3	0	0.00	-	0.00	0.00	0.0	0.0	0.0
> 20000000	-	4	0	0.00	-	0.00	0.00	0.0	0.0	0.0
Total			31	100.00	495,187	100.00	5,294.36	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E47 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.450	6.702	Based on Rate Class
Demand Rate (\$/kVA):	15.203	15.796	3.9%
Basic Charge (\$/month):	8,151.50	8,469.40	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
5000000 to 20000000	- 1	1	100.00	78,659	100.00	22,769.03	3.9	3.9	3.9

Total		1	100.00	78,659	100.00	22,769.03	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E48 by Energy Intervals
Power - Oilfield
Customer Owned Transformation -138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.260	6.504	Based on Rate Class
Demand Rate (\$/kVA):	12.038	12.507	3.9%
Basic Charge (\$/month):	8,731.50	9,072.02	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
2000000-5000000	- 1	1	50.00	24,658	6.94	7,007.00	3.9	3.9	3.9
> 20000000	- 2	1	50.00	330,451	93.06	86,926.98	3.9	3.9	3.9
Total									
		2	100.00	355,109	100.00	46,966.99	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E22 by Energy Intervals
Power
Customer Owned Transformation - 25kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.497	6.750	Based on Rate Class
Demand Rate (\$/kVA):	18.700	19.429	3.9%
Basic Charge (\$/month):	7,022.82	7,296.71	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	24	85.71	244,113	64.02	3,896.84	3.9	3.9	3.9
2000000 to 5000000	-	2	4	14.29	137,208	35.98	12,061.33	3.9	3.9	3.9
Total			28	100.00	381,322	100.00	5,063.20	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E23 by Energy Intervals
Power
Customer Owned Transformation - 72kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.450	6.702	
Demand Rate (\$/kVA):	15.203	15.796	Based on Rate Class 3.9%
Basic Charge (\$/month):	8,151.50	8,469.40	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	9	52.94	135,965	22.08	5,357.01	3.9	3.9	3.9
2000000 to 5000000	-	2	5	29.41	213,364	34.64	13,719.97	3.9	3.9	3.9
5000000 to 20000000	-	3	3	17.65	266,557	43.28	27,027.68	3.9	3.9	3.9
> 20000000	-	4	-	0.00	-	0.00	0.00	0.0	0.0	0.0

Total			17	100.00	615,886	100.00	11,640.94	3.9	0.0	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E24 by Energy Intervals
Power
Customer Owned Transformation - 138kV

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.260	6.504	Based on Rate Class
Demand Rate (\$/kVA):	12.038	12.507	3.9%
Basic Charge (\$/month):	8,731.50	9,072.02	Based on 2024 Billing

Energy Intervals (KWh/month)		Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
			Number	(%)	(MWh/year)	(%)		Average	Low	High
0 to 2000000	-	1	7	17.07	44,280	1.11	2,747.94	3.9	3.9	3.9
2000000 to 5000000	-	2	18	43.90	838,228	21.03	13,585.89	3.9	3.9	3.9
5000000 to 20000000	-	3	11	26.83	1,253,662	31.45	31,843.43	3.9	3.9	3.9
> 20000000	-	4	5	12.20	1,849,739	46.41	101,159.11	3.9	3.9	3.9
Total			41	100.00	3,985,909	100.00	27,313.53	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.

2026-27
Rate Change Impacts on E84 by Energy Intervals
Power - Time of Use
Customer Owned Transformation - 100kV & Above

Rate Breakdown	Existing	Proposed	
Energy Rate (cents/kW.h):	6.833	7.077	
Energy Off Peak Rate (cents/kW.h):	5.833	6.077	Based on Rate Class
Demand Rate (\$/kVA):	12.038	12.507	3.9%
Basic Charge (\$/month):	8,731.50	9,072.03	Based on 2024 Billing

Energy Intervals (KWh/month)	Interval	Number of Accounts		Energy Use		Average Monthly Change (\$)	% Increase		
		Number	(%)	(MWh/year)	(%)		Average	Low	High
> 20000000	- 1	6	100.00	1,887,253	100.00	88,528.47	3.9	3.9	3.9
Total		6	100.00	1,887,253	100.00	88,528.47	3.9	3.9	3.9

Based on 2024 Billing. Rates developed based on forecasted customers and consumption.



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Section 7: Load forecasts

SASKPOWER LOAD FORECAST

2025-26 Q1



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EXECUTIVE SUMMARY

OVERVIEW

SaskPower's total energy requirements are projected to rise from 26,672.0 GWh in 2025-26 to 29,584.9 GWh by 2035-36, averaging 1.0% annual growth (291.3 GWh/year), slightly below the past decade's 1.1%. Sales and demand are expected to grow at similar rates, with winter peak demand increasing from 4,103 MW to 4,553 MW (45.0 MW/year) over the same period.

All customer classes, except Residential and Power Class, are projected to experience slow to moderate growth. Most of the load growth is attributed to the Residential and Power Class sectors, with average annual increases of 2.8% and 1.3%, respectively, over the next ten years. This growth is partly due to anticipated population growth in the province and expansions in the largest customer segment.

SUMMARY OF CHANGES FROM PREVIOUS FORECAST

The tables below show the changes in the energy and peak demand forecasts between the 2025-26 Q1 and the 2024-25 Q1 forecast released last year. Most of the difference is due to changes in the mass market. Energy sales are expected to be

lower than last year on average throughout the forecast period, primarily due to reductions in the mass market forecast. The Power class is higher throughout the forecast period due to reduced self-generation and increased expansions.

Changes in 2026 Q1 vs 2025 Q1 Forecast – Energy (Gwh)

Fiscal Year	Power	Oilfield	Commercial	Residential	Farm	Reseller	Losses	Total Energy	% Change
2025-26	155	(58)	(64)	(36)	(22)	(35)	87	27	0.1%
2026-27	402	(169)	(79)	(55)	(10)	(38)	90	141	0.5%
2027-28	355	(235)	(104)	(77)	(1)	(36)	62	(35)	-0.1%
2028-29	267	(205)	(125)	(113)	10	(44)	(52)	(263)	-1.0%
2029-30	242	(169)	(131)	(146)	20	(43)	(38)	(265)	-1.0%
2030-31	296	(133)	(137)	(179)	31	(46)	(41)	(210)	-0.8%
2031-32	287	(91)	(147)	(219)	40	(46)	(65)	(243)	-0.9%
2032-33	319	(77)	(160)	(240)	47	(57)	(57)	(225)	-0.8%
2033-34	284	(81)	(163)	(236)	56	(59)	(38)	(238)	-0.9%
2034-35	249	(103)	(177)	(229)	64	(66)	(57)	(318)	-1.2%

Changes in 2026 Q1 vs 2025 Q1 Forecast – Peak (MW)

Fiscal Year	Power	Oilfield	Commercial	Residential	Farm	Reseller	Total Demand	% Change
2025-26	30	0	(5)	(2)	(4)	(8)	12	0.9%
2026-27	58	(21)	(11)	(12)	(3)	(9)	3	0.5%
2027-28	47	(40)	(20)	(22)	(4)	(11)	(50)	-0.7%
2028-29	41	(30)	(18)	(23)	1	(10)	(38)	-1.1%
2029-30	35	(26)	(20)	(31)	3	(10)	(49)	-1.2%
2030-31	43	(22)	(21)	(38)	5	(11)	(44)	-1.1%
2031-32	43	(15)	(22)	(47)	7	(12)	(45)	-1.2%
2032-33	52	(10)	(22)	(49)	10	(12)	(31)	-0.9%
2033-34	46	(11)	(24)	(52)	11	(13)	(44)	-1.0%
2034-35	39	(14)	(26)	(48)	13	(15)	(51)	-1.3%

INTRODUCTION

OVERVIEW

The Load Forecast is developed annually to determine the long-term energy requirements and system peak demand for SaskPower's customers in the province of Saskatchewan. The service area consists of the entire province except for two resale customers that supply energy to their customers in Saskatoon and Swift Current.

The 2025-26 Q1 Load Forecast was prepared for the years 2025-26 through 2035-36 using inputs from independent data sources, historical energy sales, and individual customer forecasts. The forecast is a compilation of energy sales forecasts for Power, Oilfield, Commercial, Residential, Farm, and Reseller customers and includes projections for internal Corporate Use, system losses, peak demand, unaccounted energy use, and non-grid energy use. SaskPower's load forecast forms the basis for capacity additions, maintenance schedules, power plant operations, fuel budgets, operation budgets and the corporate revenue forecast which supports both rate design and accounting.

A metered electrical service at SaskPower is considered a customer. SaskPower's customer relationship software defines a meter as an "installation." One building can have multiple installations meaning that they would be

considered multiple customers. In the power class it is also possible to consolidate multiple service points under one customer for forecast purposes. Likewise, multiple buildings served by one meter would be considered as a single installation or customer. An installation can also cover multiple streetlights.

SaskPower uses kilowatt-hours (kWh) when measuring the electrical consumption on a meter. In some cases, SaskPower uses larger denominations, such as when a multiplier is applied to the meter reading to obtain kilowatt-hours (kWh). SaskPower's forecast is presented in terms of gigawatt-hours (GWh) for the purposes of readability. One GWh is equal to one million kWh, which equals the annual energy use of approximately 125 typical residential customers.

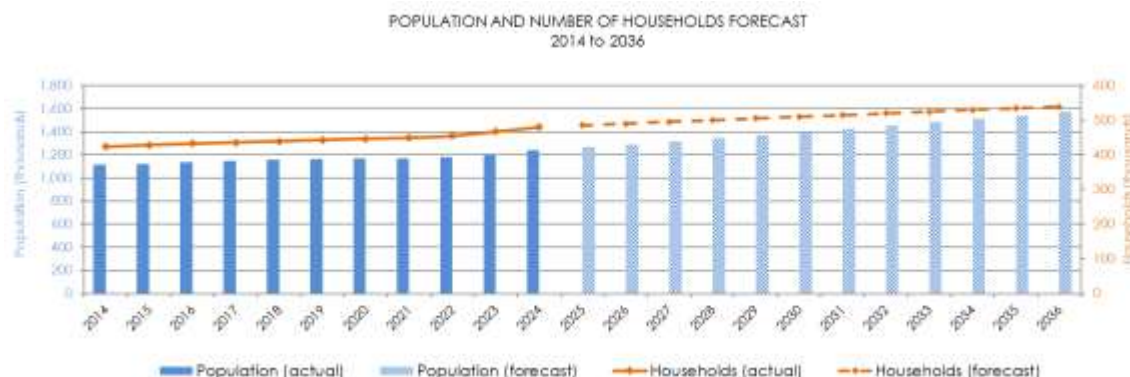
Peak load is defined as the maximum load required during a given interval of time, stated in megawatts (MW). One MW equals one thousand kilowatts (kW). The customer's demand at a specified hour is referred to as their coincident load. Their coincident peak is defined as the customer's load at the hour of SaskPower's system peak.

ECONOMIC INPUTS

An independent economist jointly hired by the Government of Saskatchewan and SaskPower provides important Saskatchewan-based inputs to the load forecast such as population, household growth, potash, and oil production forecasts. Potash production is also forecast by the Ministry of Energy & Resources. Oil production forecasts from the National Energy Board are also blended in to diversify the sources.

The population of Saskatchewan climbed from 1,114,544 in 2014-15 to 1,246,204 in 2024-25, reflecting an average annual growth rate of 1.1%. Saskatchewan's population is expected to grow at an average annual rate of 2.0 % over the next ten years. Real Saskatchewan Gross Domestic Product grew at an average annual rate of 0.7% per year over the 2014 to 2024 period and is

expected to increase annually at an average rate of 2.1% for the next 10 years.



WEATHER NORMALIZATION

Since weather can have a significant impact on the amount of electricity used by Residential, Commercial, Farm and Reseller customers, average (normalized) daily weather conditions for the last fifteen years are assumed throughout the forecast horizon. SaskPower has moved to using a 15-year period for our weather normalization.

Typically, large industrial and oilfield customers' energy consumption is not impacted significantly by weather changes. Thus, SaskPower focuses on mass market customers in the normalization process.

Actual weather data is gathered daily. Fifteen years of weather data from the Regina and Saskatoon weather stations are combined to

derive normal weather using averages. Data is ordered within each season by date, resulting in a normal daily average based on the season.

The data is then adjusted to create normalized results. A centered moving average over 30 days softens the transition over the data series (rather than having a chaotic normal). The data is then transformed into monthly or annual data for use in the forecast. Calendar weighted weather most closely matches the billing classes and, therefore, also lines up with the billing data. Calendar data is used to calculate the weights for the weather data.

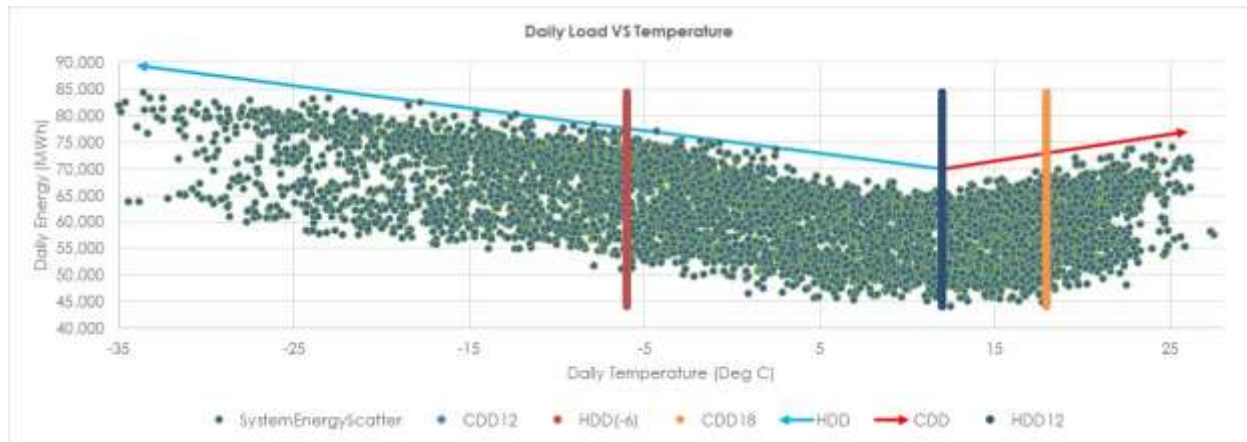
The resulting normal data series can then be used to forecast consumption into the future.

WEATHER ASSUMPTIONS

HDD and CDD

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are defined relative to a base temperature—the outside temperature above (or below) which a building typically needs no

heating (or cooling). HDDs and CDDs are a measure of the number of degrees the average daily dry bulb temperature was warmer (CDD) or cooler (HDD) than a pre-determined cut-off point multiplied by the number of days where that occurred.



SaskPower uses a variety of cut-off points and inserts them into a regression model to determine which are significant. For this forecast, HDD12, HDD (-6), CDD12, and CDD18 were determined to be the appropriate temperature break points. HDD (-6), as shown by the red vertical line in the chart above, marks the point where the temperature's impact on demand changes as the temperature drops to minus 6 degrees Celsius or lower. CDD18, shown with a vertical orange line in the chart above, reflects a change in the relationship between temperature and demand as the temperature reaches 18 degrees Celsius or above. Another breakpoint in the data occurs at 12 degrees Celsius (HDD12 and CDD12). At this temperature, load is at its lowest, due to the lowest combined heating and cooling load on the system. This is shown by a dark blue vertical line on the chart above.

Each breakpoint indicates that a material shift in energy consumption has occurred at the base temperature selected. SaskPower is a winter peaking utility because the highest annual demand on the system occurs in the winter. The graph above plots multiple year's daily load and the temperature observed on those days. When SaskPower models the weather within its forecasting software, this graph is one tool in the determination of how the impact of weather is calculated. Significant shifts in temperature are evaluated and are then applied to the heating and cooling degree days to derive a combined weather algorithm.

CUSTOMER FORECAST ASSUMPTIONS

While there are many variables that can affect load forecasts, the most significant for SaskPower are the forecasts provided by large-scale industrial and commercial customers in the Power class. SaskPower contacts these customers semi-annually to obtain short and long-term expansion

plans. This report summarizes the results of the 2025-26 Q1 load forecast which is based on discussions with Power class customers in the first quarter of 2025. An update will be prepared using data provided by Power class customers in September.

PROGRAM-BASED DEMAND SIDE MANAGEMENT (DSM) ADJUSTED FORECAST

Previously, SaskPower developed a "Base" and "DSM Adjusted" load forecast. Once the initial

Base forecast was completed using the methodology outlined above, the energy and

peak demand savings identified by Customer Services were removed. There were no DSM programs related to this forecast, thus a DSM

adjusted forecast is not required. Therefore, all tables in this report will reflect the base forecast.

PLUG-IN ELECTRIC VEHICLES

SaskPower incorporates a projected use of electric vehicles (EVs) in Saskatchewan in the load forecast. Two types of EVs are considered:

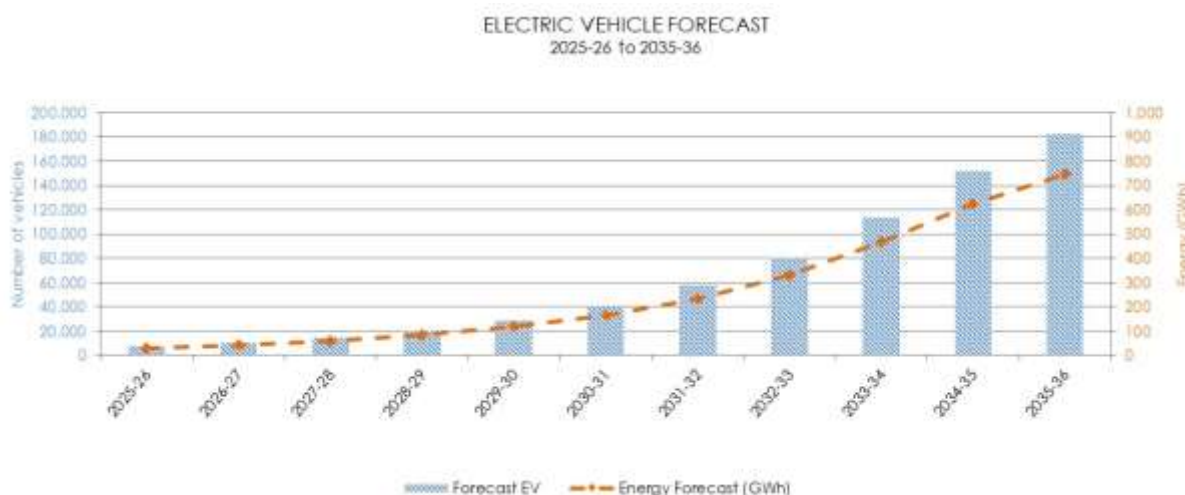
the batteries. These also can plug into an external source of power to charge the batteries.

1) Plug-In Hybrid Electric Vehicles (PHEVs):

- For long distances PHEVs run on an internal combustion engine (ICE) which either drives the vehicle directly or runs a generator to charge

2) Plug-In Electric Vehicles (PEVs):

- PEVs are charged only from an external source of power and run exclusively on battery power. They use approximately 4,100 kWh annually.



Certain types of Hybrid Electric Vehicles (HEVs) are not included in this forecast. These vehicles are not plug-in hybrids and, therefore, do not get power from SaskPower's electrical grid. One example of this type of vehicle has an ICE as well as an electric motor powered by a battery. The battery is charged using energy from both the ICE and regenerative braking. Of the twenty-five million motor vehicles¹ registered in Canada, there were 474,420 plug-ins² registered as of the

end of 2024, making up 1.84% of all vehicle registrations.

As of December 31, 2024, there were 4,774 plug-in vehicles in Saskatchewan, making up 0.50% of all registered motor vehicles. The number of PEVs is expected to increase over the forecast horizon, reaching 152,206 vehicles, or 15% of all registered vehicles in Saskatchewan by 2035-36. Total annual

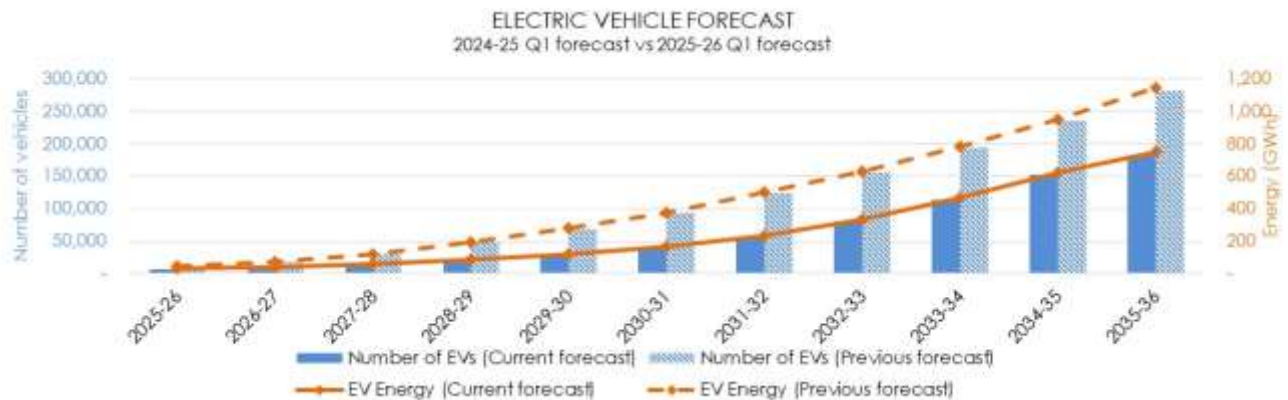
¹
<https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310030801> (25,688,408 2023 vehicle count, excludes trailers, off-road, construction and farm vehicles)

²
<https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310030801> (Combination of 2023 battery electric (329,402) and plug-in hybrid (145,018) electric vehicles)

energy consumption from PEVs is projected to be 623.2 GWh.

As the uptake of EV passenger vehicles continues to increase, the forecast is also revised. The chart

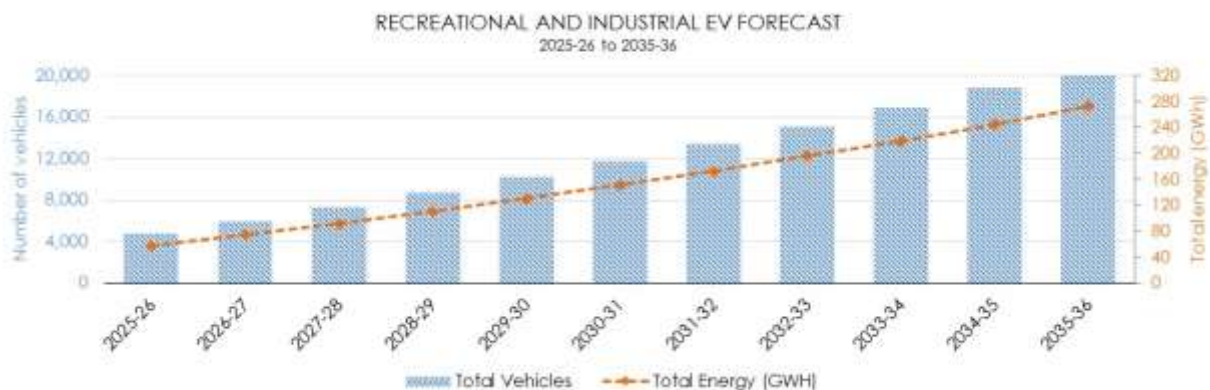
below shows the evolution of the EV forecast from the 2024-25 Q1 forecast to the 2025-26 Q1 forecast.



ADDITIONAL EVS

In addition to the registered EVs noted above, SaskPower's forecast also includes additional EVs that can be categorized into residential, commercial, and farm classes. Additional residential EVs include snowmobiles, boats, and quads. Commercial EVs include equipment such

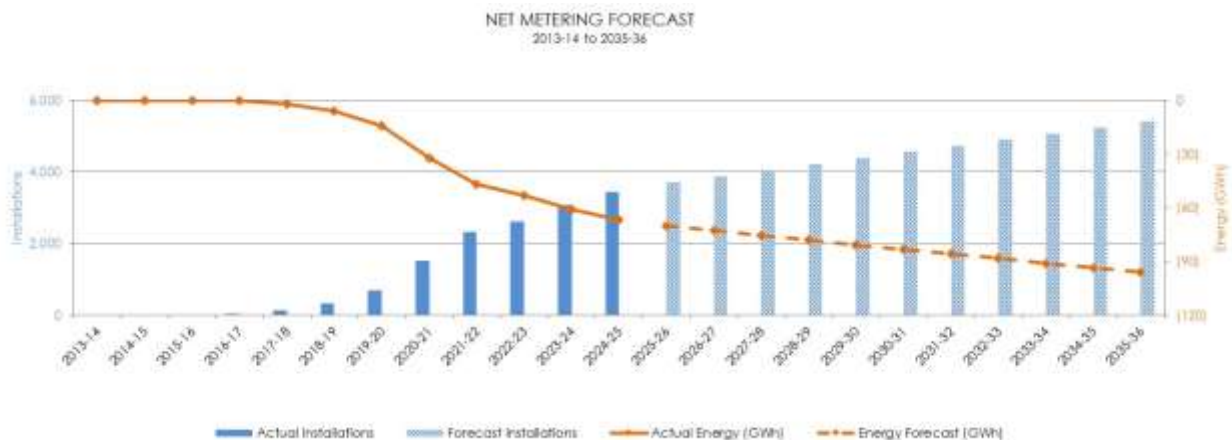
as excavators, bobcats, buses, and forklifts. For the farm class SaskPower includes electric tractors. The recreational and industrial EV forecast is projected to reach 20,970 units and 272.8 GWh by 2035-36, as summarized in the graph below.



SOLAR PHOTOVOLTAIC - BEHIND THE METER

SaskPower had 3,369 net metering customers at the end of December 31, 2024. The average capacity factor of a solar array is 14%. The average array size is 9.3 KW for Residential customers, 19.6 KW for Farms, 62.9 KW for Commercial customers, and 431.1 KW for Oilfields. This forecast assumes a degradation factor of

0.5% as the solar panels age. The total percentage of PV customers for all Residential, Commercial, Oilfield and Farm customers is expected to reach 0.9% in 2035-36, while total energy production is expected to reduce energy loads by 96.1 GWh in 2035-36.



BATTERY STORAGE

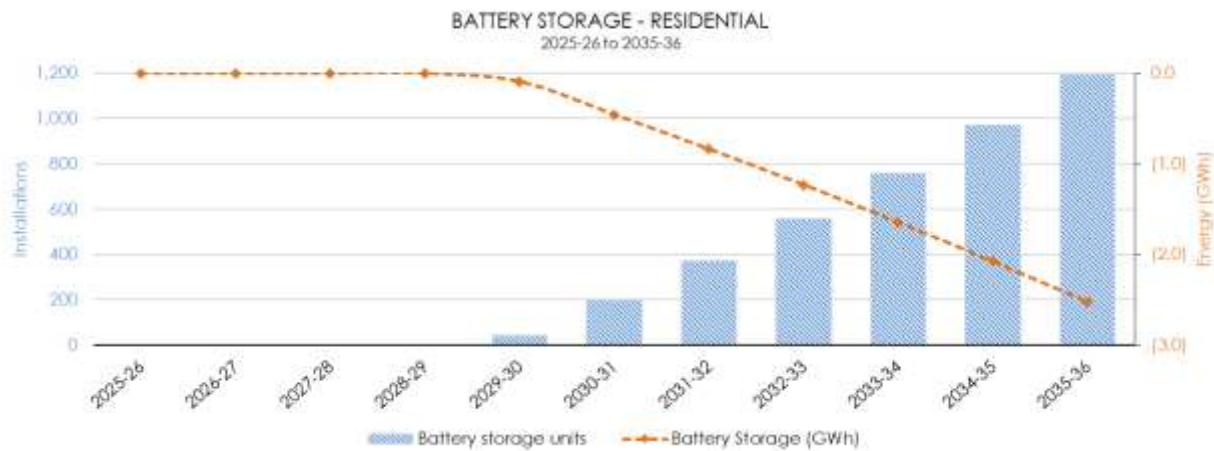
Residential

SaskPower anticipates more customers will install battery storage units. Candidates for this are net metering customers. This is due to the difference in the value of a kWh sold to SaskPower versus a kWh generated internally by the customer. Under the terms and conditions of SaskPower's Net Metering 2.0 program, SaskPower pays 7.5 cents/kWh for any energy sold to SaskPower but charges a residential customer 14.895 cents/kWh. Net metering customers could potentially save money through the purchase of a battery storage unit.

Calculations are based on technical statistics obtained from the Tesla Power Wall including

usable battery energy (not all the energy can be used in a battery), Round-Trip Efficiency (a measure of the losses for the DC conversion and the AC inversion), and a degradation of the battery of 3% per year.

The model assumes that 1% of net metering customers install batteries in 2029-30, followed by an accelerating adoption rate of an additional 5% per year starting in 2030-31. SaskPower anticipates that Residential customers will install 1,193 battery storage units by 2035-36, resulting in 2.5 GWh of electricity being removed from the grid.



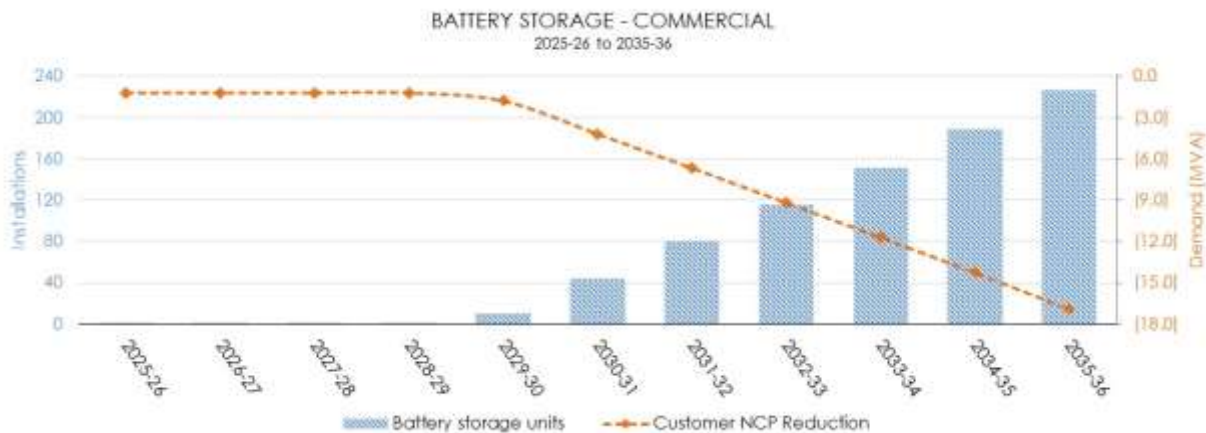
Commercial

SaskPower expects that some commercial customers will install battery storage units. Those who pay for demand and are subject to the ratchet clause would have interest in installing these units. There is a potential savings for customers if these units were used to reduce their peak demand.

SaskPower assumes that these systems are used to perform peak shaving and that they typically will not be used to provide baseload power for extended periods of time. Unlike the Residential

class, no adjustments are made for commercial battery storage units to account for usable battery energy or Round-Trip Efficiency.

The model assumes an accelerating adoption rate of an additional 1% per year of total commercial customers: 1% in 2029-30, 2% in fiscal 2030-31, etc. SaskPower anticipates that Commercial customers will install 226 battery storage units by 2035-36, removing 16.9 MVA from the grid.



REGULATORY OVERSIGHT

SaskPower's load forecast methodology is typically reviewed by outside industry experts every five years as recommended by the Saskatchewan Rate Review Panel. The purpose of the review is to determine if the methodology is appropriate for SaskPower and is consistent with accepted electric power utility practices.

The most recent methodology review was completed in 2024 by iTron Inc. iTron provided

verification of SaskPower's methodology and provided some recommendations for enhancements using their own forecasting expertise as well as an in-depth industry survey. Several of the recommendations were accepted from the study and implemented in our forecast processes starting in 2025.

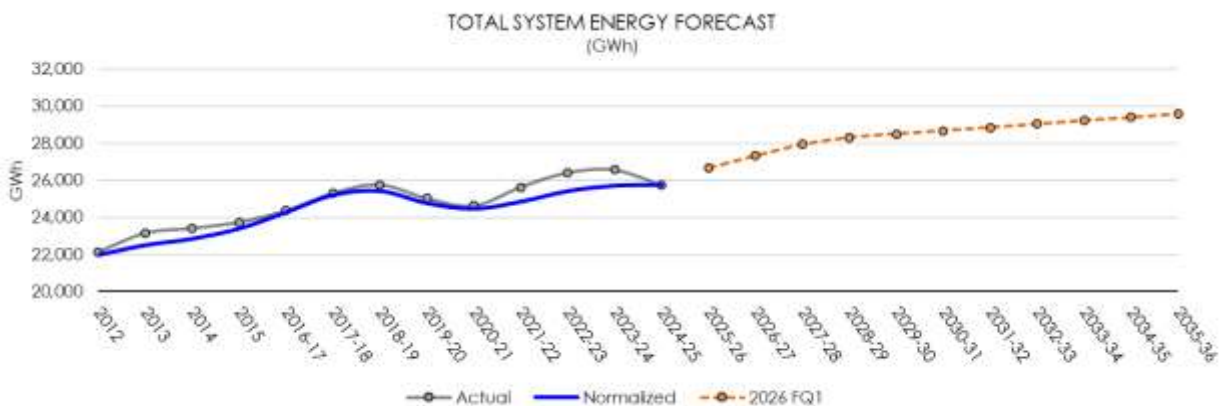
The next review is scheduled for 2029.

TOTAL SYSTEM LOAD FORECAST - SUMMARY

TOTAL SYSTEM ENERGY

The 2025-26 Q1 load forecast predicts a 2,912.9 GWh increase in the total system energy requirements over the next 10 years. This increase from 26,672.0 GWh in 2025-26 to 29,584.9 GWh in 2035-36 translates into an average annual growth rate of 1.0% over the 10-year period (refer to **Table**

A1). Over the previous decade, the historical average annual growth rate was 1.1%. Note that SaskPower's fiscal year changed from a calendar year to the twelve-month period ending March 31 starting in 2016-17.

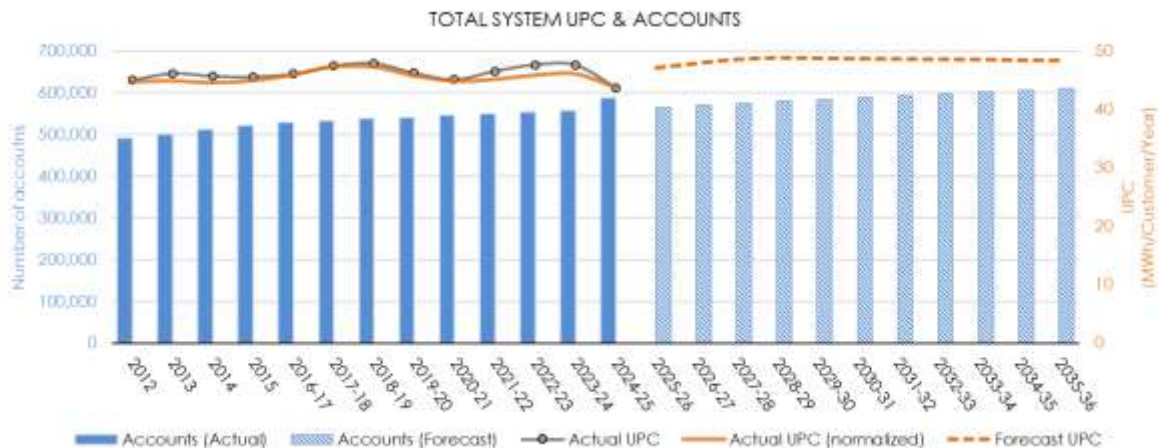


TOTAL USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts an increase in the total number of customer accounts of 45,127 (including Corporate Use) over the next 10 years. This increase from 565,861 in 2025-26 to 611,014 in 2035-36 translates into an average annual growth rate of 0.8% over the 10-year period (refer to **Table A1**). The historical average

annual growth rate was 0.9% for the years 2014 to 2024-25.

Average Use per Customer (UPC) is expected to increase from 47.1 MWh to 48.5 MWh over the forecast horizon, driven primarily by the higher overall energy forecast.



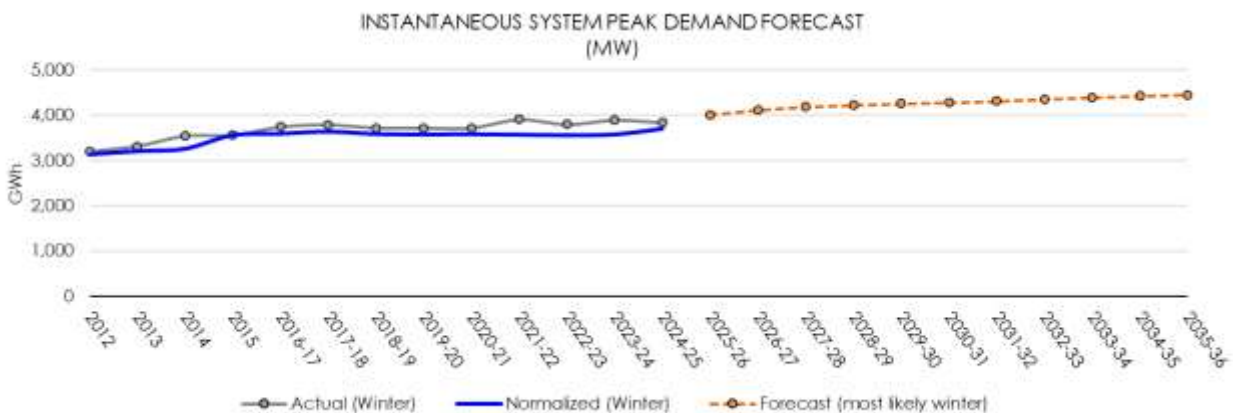
SYSTEM PEAK LOAD

SaskPower generates both potential and most likely peak demand forecasts, for instantaneous and interval time periods. Instantaneous peak demand is the maximum system demand at the instant of greatest load, while the interval peak demand is the maximum system demand averaged over a given period (i.e., 60-minutes).

Potential system peak demand represents the highest level of demand placed on the supply system at any time during the year if typical Christmas lighting loads occur and all large consumers are operating at their normal levels

with below average weather conditions. Potential peaks are used for SaskPower's planning purposes and represent the maximum demands SaskPower must be prepared for if all these conditions are met.

The most likely system peak demand forecast represents the highest level of demand placed on the supply system at any time during the year if typical lighting loads occur and all large consumers are operating at their normal levels under five-year average weather conditions.



The potential instantaneous fiscal system peak demand is expected to increase by 450 MW from 4,103 MW in 2025-26 to 4,553 MW in 2035-36. This equates to an average annual growth rate of

1.0%. The most likely instantaneous fiscal system peak demand is forecasted to increase from 4,018 MW to 4,459 MW over the same period, representing an average annual growth rate of

1.0% per year (Refer to **Table A4**). Of the increase in peak, 40.5% is attributable to the Residential Class, 47.8% is attributable to the Power sector, while all other classes make up 11.7%. The system peak demand grew at an average annual rate of 0.8% from 2013 to 2023-24.

Table A4 provides the summer potential and most likely peak forecasts, which assumes sustained hot weather occurring in July.

CHANGES FROM PREVIOUS FORECAST

Total System Energy Forecast

Total system energy is lower than the previous forecast by an average of 167 GWh per year. This is due similar decreases in Residential, Oilfield, and Commercial class energy requirements. Customer

counts are lower throughout the forecast period, UPC is still higher primarily due to power and oilfield.

CHANGE IN TOTAL SYSTEM FORECAST (GWH)

Comparison of 2025 FQ1 forecast to 2024 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	UPC	Difference			%
				Customer	Total		
2025-26	26,672	26,650	88	-67	22		0.1%
2026-27	27,332	27,190	263	-122	141		0.5%
2027-28	27,940	27,979	139	-178	-39		-0.1%
2028-29	28,324	28,584	-36	-224	-260		-0.9%
2029-30	28,507	28,773	0	-266	-266		-0.9%
2030-31	28,688	28,900	99	-311	-212		-0.7%
2031-32	28,862	29,111	114	-362	-249		-0.9%
2032-33	29,044	29,269	184	-410	-225		-0.8%
2033-34	29,239	29,482	209	-452	-243		-0.8%
2034-35	29,403	29,727	176	-500	-324		-1.1%
Average	28,401	28,567	124	-289	-165		-0.6%
Total	284,011	285,665	1,238	-2,893	-1,655		-0.6%

System Peak Demand

The most likely peak is expected to be lower than the previous forecast by an average of 146 MW per year. The peak forecast is derived by applying

historical coincident load factors to each class's energy forecast. The lower peak forecast is driven by lower coincident peaks in all classes.

TOTAL SYSTEM PEAK REQUIREMENTS FORECAST (MW)

Fiscal Year	2026 FQ1	2025 FQ1	Difference	%
2025-26	4,018	3,983	34	0.9%
2026-27	4,115	4,093	23	0.5%
2027-28	4,189	4,219	(30)	-0.7%
2028-29	4,226	4,271	(45)	-1.1%
2029-30	4,258	4,312	(54)	-1.2%
2030-31	4,287	4,333	(46)	-1.1%
2031-32	4,313	4,366	(54)	-1.2%
2032-33	4,358	4,396	(38)	-0.9%
2033-34	4,395	4,441	(46)	-1.0%
2034-35	4,428	4,487	(58)	-1.3%
Average	4,259	4,290	(31)	-0.7%
Total	42,588	42,902	(314)	-0.7%

POWER CLASS FORECAST DETAILS



- Pipelines, Manufacturing, Mining, Refining, Food Processing, Large Public and Private Buildings
- 40-45 % of Sales
- 40% of Peak
- Uncertainty of expansion and customer generation present challenges in this sector
- Only 0.0002% of customers

DEFINITION

A Power Class customer is defined as any large commercial or industrial customer who is currently on SaskPower's Standard Power Class rates or who has negotiated an Electrical Service Agreement (ESA) with SaskPower.

The 2025-26 Q1 Power class load forecast is a compilation of individual forecasts for each customer in the class. Each customer forecast includes firm load and speculative load when

applicable. Firm load includes each customer's base loads as well as projects or expansions which are highly likely to proceed. Normally these projects are two to three years out, and the project has been announced and approved. Speculative loads include longer term expansion plans or new projects which have not been approved, or have a lower probability of proceeding, as determined in consultation with the customer.

METHODOLOGY

Several different methods are used to derive energy forecasts for power class customers. These methods include individual energy forecasts as provided by the customer, energy forecasts based on production estimates, energy intensity levels and regression analysis, and energy forecasts determined through extrapolation of current loads. The method employed is dependent upon a customer's industry and the availability of information for that customer or industry.

SaskPower consults with the Ministry of Energy & Resources annually to review mine expansion plans in the province. SaskPower also develops a potash sector energy forecast based on the Ministry of Energy & Resources' potash production forecast. This forecast is used to compare to, and adjust, the individual potash customer forecasts, as required.

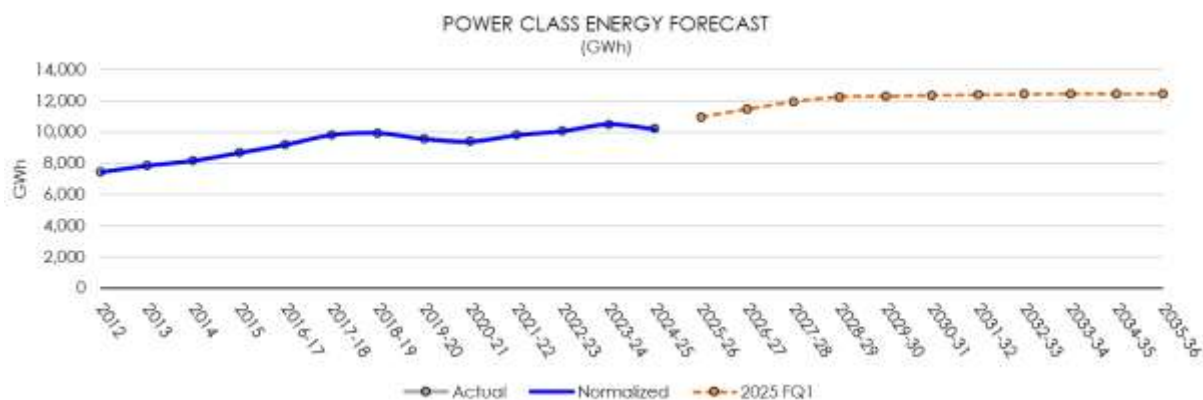
FORECAST ASSUMPTIONS

- Monthly maintenance schedules for individual power customers are determined either by the customer's forecast or by assuming the same historical maintenance cycle.
- All customers who have ESAs with SaskPower are included in the power class forecast.
- SaskPower will maintain its current customer base and market share, except where self-generation replaces SaskPower as the supplier.
- All potential expansion and contraction initiatives, including customer self-generation, are applied a probability of occurrence and start date and netted against the customer's existing base load requirements.
- Speculative load includes projects specifically identified by power class customers, except in the case of the potash industry where production forecasts provided by the Ministry of Energy & Resources produces a 'miscellaneous' speculative component.
- An assumption is made that a new power class customer will be added every five years, starting in year 10th year, based on a representative power class operating profile.

POWER CLASS ENERGY FORECAST

The total Power Class sales forecast (including probable load) is expected to rise from 10,968.2 GWh in 2025-26 to 12,472.5 GWh in 2035-36. The total increase of 1,504.2 GWh equates to an average annual increase of 1.3% over the 10-year period (Refer to **Table A1**). Energy sales for the Power class have grown at an average rate of 2.3% per year from 2014 to 2024-25. In 2010, Power

class loads returned to levels exceeding those before the economic downturn in 2007-08 and experienced steady or increasing growth until 2019-20. A downturn in the province's resource sector, compounded by the economic impacts of COVID-19 in 2020-21 resulted in lower energy sales through 2020-21.



POWER CLASS USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast projects no change in power class accounts over the next 10 years.

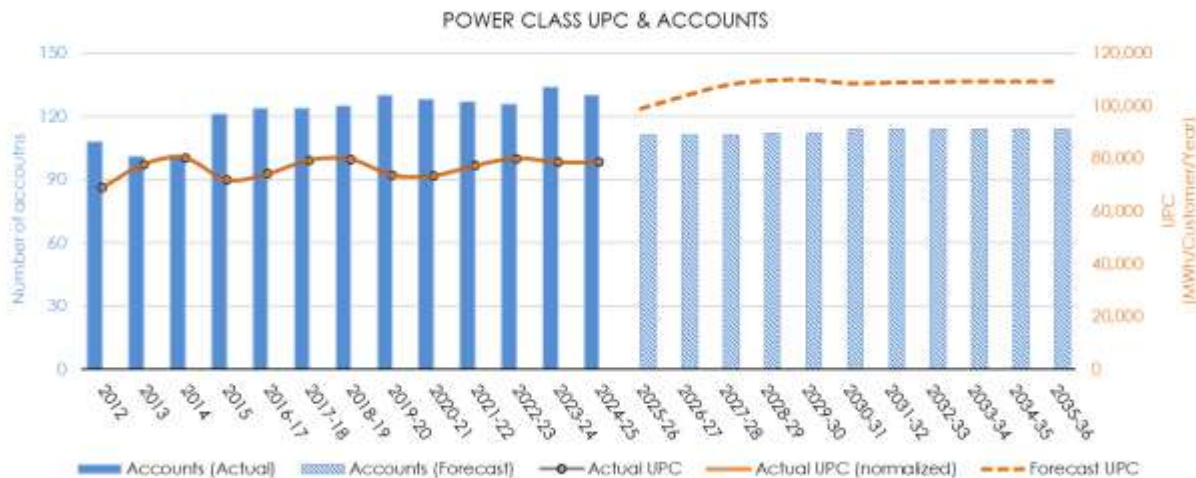
This results in a 0.0% growth rate from 2025-26 to 2034-35 (refer to Table A1).

Since a Power customer can be comprised of multiple sites within an account, the projected increases are not necessarily indicative of the total customer growth. The historical average annual growth rate was 0.8% for the years 2014 to 2024-25.

CHANGES FROM PREVIOUS FORECAST

The cumulative 2025-26 Power class forecast is projected to be 2,856 GWh (2.4%) higher than the previous year's forecast over the 10-year horizon, averaging 286 GWh/year. The increase is due to factors such as higher potash and northern mine energy sales, partially offset by decreases in the

pipeline sector. These adjustments will result in the average UPC increasing from 82,468 to 92,317 MWh/customer/year, or 1.1%. Customer growth is expected to be 3.7% lower on average than the previous forecast.



POWER CLASS FORECAST (GWH)

Comparison of 2025-26 FQ1 to 2024-25 FQ1

Fiscal Year	2026 FQ1	2025 FQ1	Difference			
			UPC	Customer	Total	%
2025-26	10,968	10,813	2,527	-2,372	155	1.4%
2026-27	11,489	11,087	2,990	-2,588	402	3.5%
2027-28	11,961	11,606	3,049	-2,694	355	3.0%
2028-29	12,282	12,015	2,898	-2,632	267	2.2%
2029-30	12,322	12,080	2,882	-2,640	242	2.0%
2030-31	12,385	12,089	2,686	-2,390	296	2.4%
2031-32	12,413	12,126	2,682	-2,395	287	2.3%
2032-33	12,443	12,124	2,720	-2,401	319	2.6%
2033-34	12,475	12,191	2,691	-2,407	284	2.3%
2034-35	12,463	12,214	2,654	-2,405	249	2.0%
Average	12,120	11,834	2,778	-2,492	286	2.4%
Total	121,201	118,345	27,780	-24,925	2,856	2.4%

POWER ACCOUNT MAJOR SECTOR SUMMARY (TABLE A5)

- Potash Sector:**
 Potash production forecasts continue to show robust growth, offset marginally by self-generation within the sector. By 2035-36, the annual sector load is forecast to increase by 836 GWh, representing an average expansion rate of 2.5% per year (see **Table A5**).
- Pipeline Pumping Sector:**
 Forecast loads in the short term are remarkably high and have been increasing in the most recent years. This iteration of the forecast assumes that the load growth in the pipeline sector will cool slightly over the next 10 years, contracting 118 GWh, representing a reduction of 0.3% per year (see **Table A5**).
- Northern Mining Sector:**
 The Northern Mining sector consists of the uranium and other mines supplied through the northern transmission system. The possibility of new nuclear generation development as one of the responses to climate change has spurred renewed interest in uranium exploration and extraction. Additionally, the war in Ukraine continues to destabilize the global uranium supply to the point where power plants may look for alternative sources. The sector is expected to increase 59 GWh in the 10-year period. This represents an average growth of 1.3% per year (see **Table A5**).
- Speculative Load:**
 Speculative loads are longer term expansion plans or new projects which have not been approved, or have a lower probability of proceeding, as determined in conjunction with the customer. Each project in the forecast is assigned an expected MVA requirement as well as the probability of completion and a start date. The individual speculative MVA for each project is multiplied by the probability and included in the total load for its start year. In some cases, a construction power ramp up is included. The speculative sector is more diversified than in recent years with agriculture and grain processing accounting for a sizable portion of the projects, along with potash and other

mining (see **Table A5**). Total energy growth from speculative projects is 558 GWh over the forecast horizon.

Data centres play a significant role in digital infrastructure and cloud computing and offer potential opportunities to utilities worldwide. SaskPower continues to closely monitor developments within this sector and is actively engaging with our shareholder, Crown Investments Corporation, to formulate a comprehensive strategy and prospective roadmap for data centre development in Saskatchewan.

- Self-Generation:

The likelihood of customer self-generation via a variety of generation technologies has increased in recent years, although some projects have been scaled back or cancelled. The potential for self-generation has been incorporated into the power class forecast by identifying individual projects - to the extent known - and assigning MVA sizes and probabilities to them. The resulting decrease in energy sales is included in the power class forecast. In some cases, the self-generation is already operational.

IMPACT OF SELF-GENERATION

2025-26 FQ1 Forecast

Known Projects	Potential Size (mVA)	In-Service Year
Project 1	-57.0	2025
Project 2	-1.6	2025
Project 3	-29.0	2026
Project 4	-100.0	2027
Project 5	-30.0	2027
Project 6	-10.0	2028
Total	-227.6	

OILFIELD FORECAST DETAILS



- Oil and gas extraction
- 16.5%-18% of Sales
- 14% of Peak
- Sector shows steady consumption in the near to mid-term with a reduction in the long-term
- 3% of customers

DEFINITION

Oilfield customers are those involved in individual oil and gas production and 'in-field' oil pumping and processing services. The Oilfield class is

- Lloydminster Heavy
- Lloydminster Medium
- Lloydminster Light
- Kindersley Heavy
- Kindersley Medium
- Kindersley Light

Due to the global nature of the oil and gas market, oil production in Saskatchewan is heavily influenced by the world market. It is affected by

comprised of wells pumping oil from underground patches throughout Saskatchewan. These wells are separated into twelve regions:

- Estevan Medium
- Estevan Light
- Estevan Heavy
- Swift Current Medium
- Swift Current Light
- Swift Current Heavy

the demand for and price of oil and gas and by provincial royalty structures.

METHODOLOGY

Econometric, extrapolation and statistical regression methods are used to determine the future energy requirements of the Oilfield class. The number of customer accounts is estimated using the existing number of customers and extrapolated based on historical trends, as well as building in a future expected growth rate.

To determine the energy forecast for the Oilfield class, a regression analysis is developed for energy intensity in kWh per cubic metre of oil or fluid (oil and water) production by year for each region. The forecasted oil production is provided by the Ministry of Energy & Resources, the National Energy Board (NEB), and the Canadian

Association of Petroleum Producers (CAPP). Forecasted water production volumes are based on historic water cut trends. The forecasted energy requirements are then calculated using the regression analysis results and the forecasted oil or fluid (oil and water) production.

Large Oilfield customer forecasts are prepared on an individual basis. The methodology for the preparation of this forecast is based on historical usage patterns, individual customer information (if available), along with the appropriate growth drivers provided by the Ministry of Energy & Resources.

ASSUMPTIONS

- Oil production forecasts for the years 2025 to 2036 are provided by the Ministry of Energy & Resources, the National Energy Board (NEB) and by the Canadian Association of Petroleum Producers (CAPP) when available.
- SaskPower will maintain its current customer base and market share, except where self-generation replaces SaskPower as the supplier.

OILFIELD PRODUCTION FORECAST

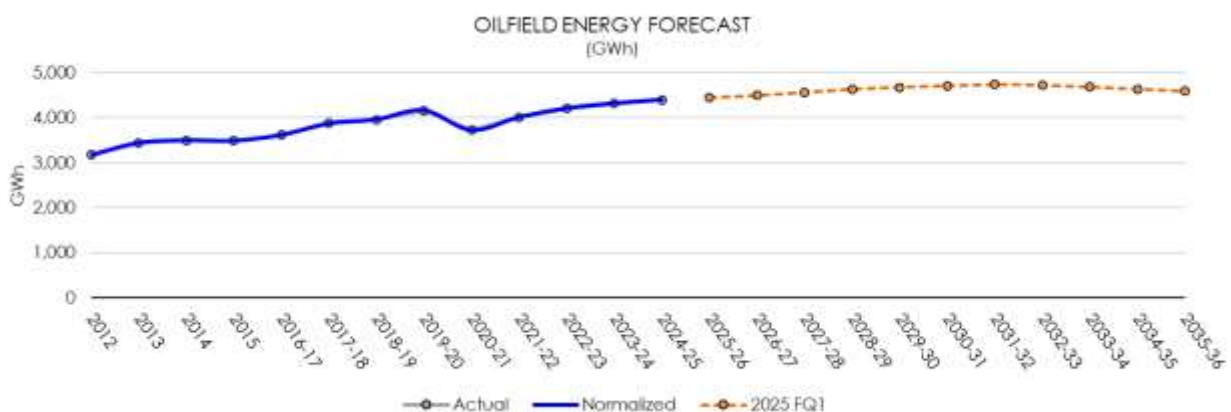
Using the production forecasts provided by the National Energy Board (NEB), and the Ministry of Energy & Resources, SaskPower projects that

oilfield production will increase by an average of 138.3 cubic metres/year (approximately 0.6%) until 2036.

OILFIELD ENERGY FORECAST

The 2025-26 Oilfield forecast predicts energy sales to grow from 4,452.8 GWh to 4,590.2 GWh in 2035-36. The increase of 137.4 GWh equates to an average annual growth rate of 0.3% over the ten-year period (Refer to **Table A1**). Production is expected to increase over the 10-year horizon, as Saskatchewan's aging oilfields require more

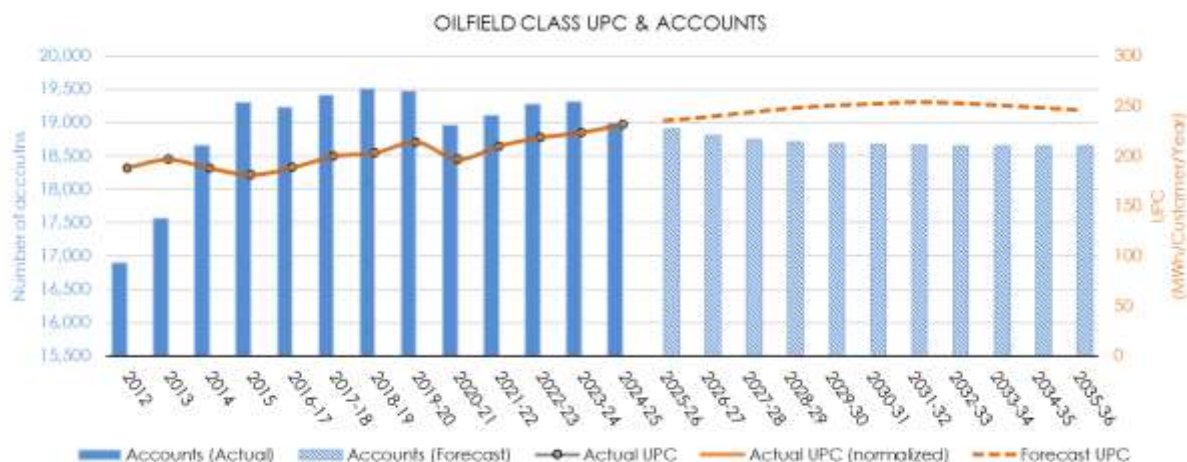
energy to extract oil from reserves including the use of CO₂ injection to enhance oil recovery. The increased energy intensity of existing wells is a significant reason for the increase in oilfield sales. Energy sales for the oilfield sector have grown at an average rate of 2.3% per year from 2014 to 2024-25.



OILFIELD USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts a decrease of 261 customer accounts over the next 10 years. This decrease from 18,928 in 2025-26 to 18,667 in

2035-36 translates into an average annual growth rate of -0.1% over the 10-year period (refer to **Table A1**).



The historical average annual customer growth rate was 0.2% from 2014 to 2024-25. UPC is expected to increase from 235.6 MWh to 246.2

MWh over the forecast horizon, due primarily to the increased energy intensities of Saskatchewan's aging oilfields.

CHANGES FROM PREVIOUS FORECAST

Compared to the previous forecast, the annual energy requirements for the Oilfield class are projected to average 263 GWh/year more than

the previous forecast over the 10-year horizon. Forecasted energy is expected to be higher throughout the forecast.

OILFIELD FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	Difference			
			UPC	Customer	Total	%
2025-26	4,453	4,511	81	-139	-58	-1.3%
2026-27	4,498	4,667	46	-215	-169	-3.8%
2027-28	4,565	4,800	45	-279	-235	-5.1%
2028-29	4,634	4,840	101	-307	-205	-4.4%
2029-30	4,679	4,848	148	-316	-169	-3.6%
2030-31	4,707	4,841	183	-317	-133	-2.8%
2031-32	4,737	4,829	222	-313	-91	-1.9%
2032-33	4,722	4,799	222	-300	-77	-1.6%
2033-34	4,682	4,763	201	-282	-81	-1.7%
2034-35	4,638	4,740	165	-268	-103	-2.2%
Average	4,631	4,764	141	-274	-132	-2.9%
Total	46,315	47,637	1,415	-2,737	-1,322	-2.9%

This increase in projected energy consumption is due to an anticipated increase in the Use per Customer from the previous forecast. The 2024-25 forecast predicts there will be an average of 140 fewer accounts per year. The decrease in customers results in an average decrease of 140

GWh per year from the previous forecast. The increase in anticipated UPC averages 14.1 MWh/customer/year and leads to an average increase of 263GWh per year. The net impact of these changes results in an average net increase of 122 GWh/year over the forecasted period.

COMMERCIAL & STREETLIGHT FORECAST DETAILS



- Public and private buildings, stores, restaurants, small manufacturing and processing facilities, skating rinks, swimming pools, streetlights
- 15 % of Sales
- 14 % - 15 % of Peak
- 12% of customers

DEFINITION

Commercial customers are defined as non-residential, non-farm, and non-oilfield customers not included in any other category. This customer

class consists of customers involved in a wide range of activities, varying from small and large business establishments to streetlights.

METHODOLOGY

Econometric, extrapolation, end use and statistical regression methods are used to develop the energy forecast for the Commercial class. The forecasted number of commercial customers forecast is determined by developing an exponential smoothing model. This exponential smoothing also contains expectations of future growth based on historical growth to determine the future number of commercial customers.

Forecasted Commercial class energy sales are determined by first removing the Streetlight load

from the Commercial class. The remainder of the Commercial class load is forecasted using a regression analysis of commercial use per customer using weather and end uses. No GDP variables were found to be statistically significant this forecast cycle.

The forecasted customer indicators for these categories from the customer forecast and the regression analysis results are used to forecast future Commercial class energy sales.

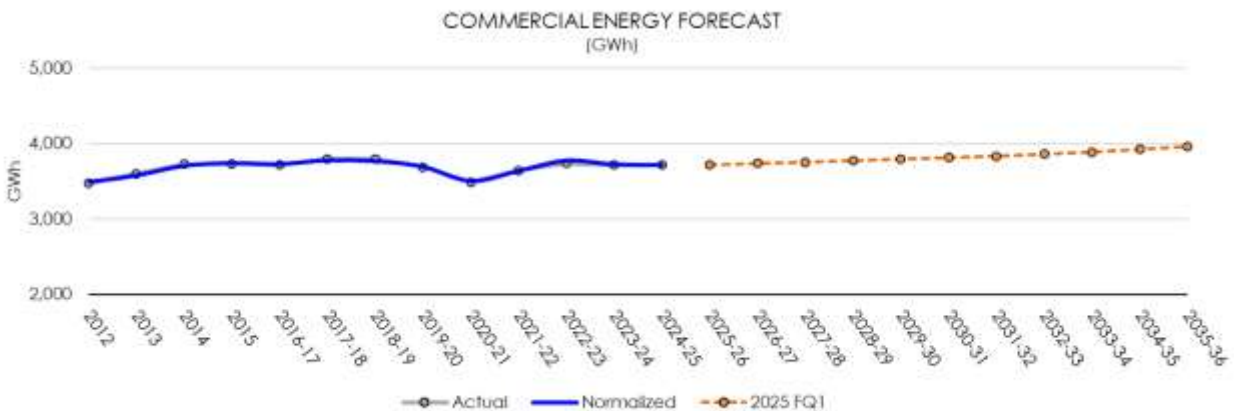
ASSUMPTIONS

- Electrical usage for commercial customers assumes weather conditions equivalent to the average weather conditions over the last fifteen years.
- SaskPower will maintain its current customer base and market share, except where self-generation replaces SaskPower as the supplier.

COMMERCIAL ENERGY FORECAST

Energy sales to the Commercial class are expected to grow from 3,722.5 GWh in 2025-26 to 3,961.5 GWh in 2035-36. This 239.1 GWh increase translates into an average annual growth rate of 0.6% over the same period. Energy sales for the Commercial class have shrunk at an average rate

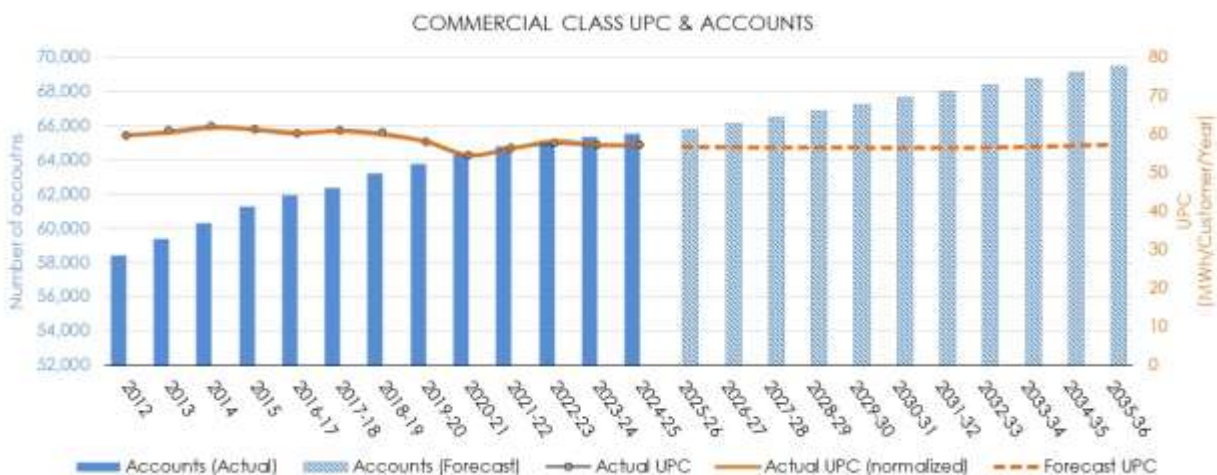
of -0.03% per year from 2014 to 2024-2025. The load growth in the forecast reflects a more typical level of economic activity in the province as well as incremental increases to reflect the Commercial sector reversing the effects of the pandemic.



COMMERCIAL USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts an increase in the total number of customer accounts of 3,702 over the next 10 years. This increase from 65,744 in 2025-26 to 69,446 in 2035-36 translates into an average annual growth rate of 0.6% over the 10-

year period. The historical average annual growth rate was 0.8% from 2014 to 2024-25. UPC is expected to increase from 56.6 MWh to 57.0 MWh over the forecast horizon.



CHANGES FROM PREVIOUS FORECAST

The average annual energy requirements for the commercial class are projected to be 125 GWh/year lower than the previous forecast. Anticipated energy usage is expected to remain lower than the previous forecast over the entire 10-year horizon.

The number of customers is expected to increase from last year's forecast by an average of 151

customers/year, resulting in an average annual energy increase of 9 GWh/year. Use per customer, is lower on average from 56.6 to 58.5 MWh/customer/year, resulting in a decrease in expected usage of 133 GWh/year. The net impact of these changes results in an average decrease of 125 GWh/year over the forecasted period.

COMMERCIAL FORECAST (GWH)

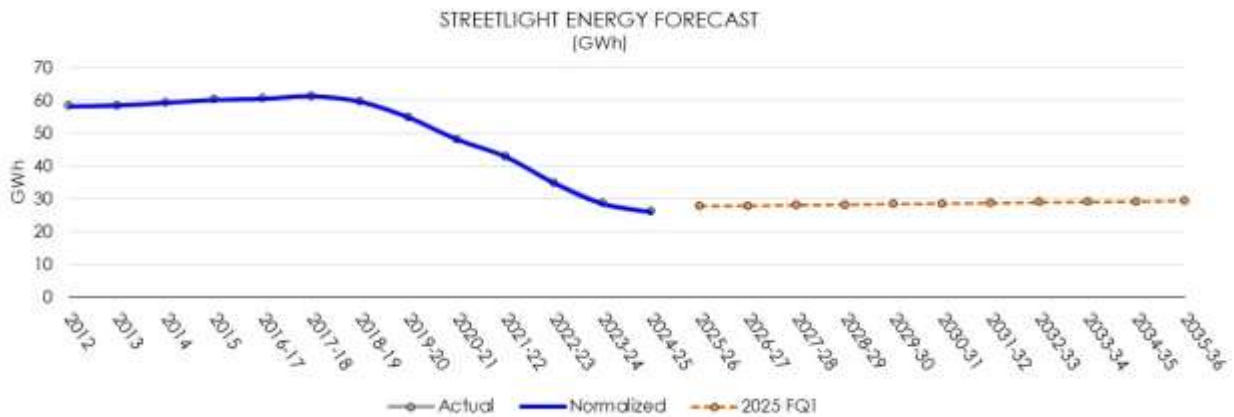
Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	UPC	Difference		
				Customer	Total	%
2025-26	3,722	3,783	-58	-2	-60	-1.6%
2026-27	3,740	3,815	-76	0	-75	-2.0%
2027-28	3,758	3,858	-103	3	-100	-2.7%
2028-29	3,778	3,899	-126	5	-121	-3.2%
2029-30	3,798	3,925	-134	7	-127	-3.3%
2030-31	3,816	3,949	-143	10	-133	-3.5%
2031-32	3,837	3,979	-155	12	-143	-3.7%
2032-33	3,861	4,017	-170	14	-156	-4.0%
2033-34	3,890	4,049	-175	17	-159	-4.1%
2034-35	3,926	4,098	-191	19	-172	-4.4%
Average	3,813	3,937	-133	9	-125	-3.3%
Total	38,126	39,371	-1,330	85	-1,245	-3.3%

STREETLIGHTS ENERGY FORECAST

Streetlights pertain to any SaskPower-owned street, highway, or pedestrian walkway lighting. The streetlight energy forecast is determined by

the number of residential customers as well as extrapolating past trends in streetlight energy usage into the future.



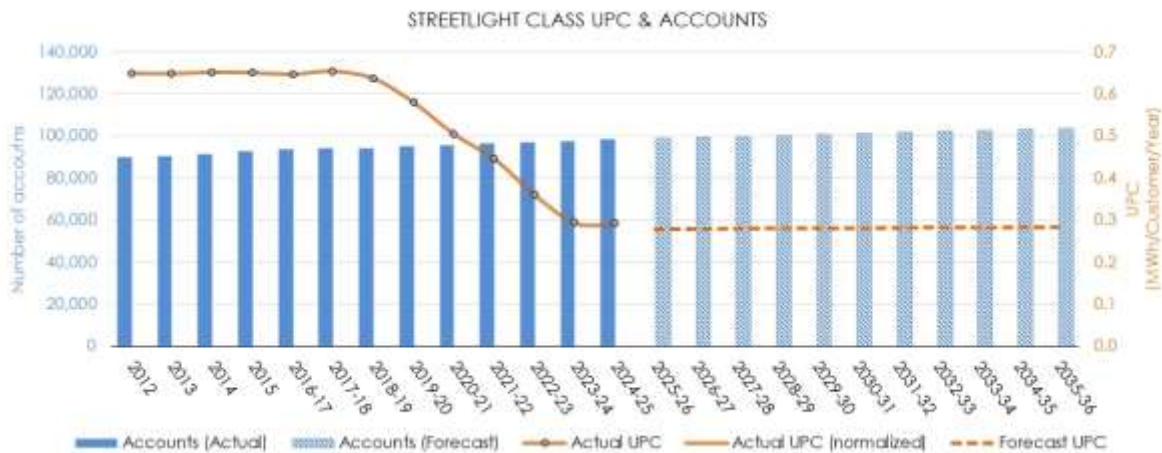
Forecasted energy usage for streetlights is expected to increase as the province grows.

Anticipated energy use is projected to increase from 27.6 GWh in 2025-26 to 29.4 GWh in 2035-36.

STREETLIGHT USE PER CUSTOMER (UPC) AND NUMBER OF STANDARDS

The 2025-26 Q1 load forecast predicts an increase in the total number of streetlight standards of 4,832 over the next 10 years. This increase from 98,895 in 2025-26 to 103,727 in 2035-36 translates into an average annual growth rate of 0.5% over the 10-

year period. The historical average annual growth rate was 0.8% from 2014 to 2024-25. UPC is expected to increase from 0.280 MWh to 0.283 MWh over the forecast horizon.



CHANGES FROM PREVIOUS FORECAST

The cumulative 2024-25 streetlight forecast is projected to be marginally lower than the previous year forecast over the 10-year horizon. As

all bulbs are now LED the forecast is expected to grow as the province grows.

STREETLIGHT FORECAST (GWH)

Comparison of 2025 FQ1 forecast to 2024 FQ1 Forecast

Fiscal Year	2024 FQ1	2025 FQ1	UPC	Difference		
				Customer	Total	%
2025-26	28	31	-3	-0	-3	-12.4%
2026-27	28	31	-3	-0	-4	-13.0%
2027-28	28	32	-4	-0	-4	-13.3%
2028-29	28	32	-4	-0	-4	-13.7%
2029-30	28	32	-4	-0	-4	-14.4%
2030-31	28	33	-4	-0	-4	-14.9%
2031-32	29	33	-4	-0	-4	-15.4%
2032-33	29	33	-4	-0	-4	-15.6%
2033-34	29	34	-4	-0	-5	-16.4%
2034-35	29	34	-4	-1	-5	-16.8%
Average	28	33	-4	-0	-4	-14.6%
Total	284	326	-38	-3	-41	-14.6%

Account growth is 1.1% lower than the previous forecast, translating into an average decrease of 1,146 accounts/year. Historical UPC is lower than expected which has driven forecast UPC lower

than last year by 4 MWH/Customer/year. The net result is a decrease of 4 GWH/year to average annual energy.

RESIDENTIAL FORECAST DETAILS



- Single-detached homes, single – attached homes, apartments, rural
- 13-15 % of Sales
- 13% - 15% of Peak
- Potential for increased power needs for EVs and electric heat
- 75% of customers

DEFINITION

The Residential class includes customers occupying residential premises, including apartment units, resort cottages and domestic

outbuildings. Residential customers served by municipal utilities in Swift Current and Saskatoon are excluded from this customer class.

METHODOLOGY

Econometric, end use, extrapolation and statistical regression methods are used to predict future residential customers' energy requirements. Energy sales to the residential class are forecasted based on the number of residential customers and the average use per residential customer.

The number of residential customers is determined using households as provided through independent data sources. The average use per residential customer is calculated based on the type of household, end use market conditions and efficiency standards. This methodology includes twenty-one end uses. The use per appliance calculation considers market saturation and penetration rates, average load of appliances, hours of use, life expectancy and efficiency

standards. Saturation rates are based on data from the 2015 Residential End Use Survey as well as US Energy Information Administration data. Efficiency standards are based on information from Statistics Canada and the US Energy Information Administration. Latest information was obtained in 2022 from iTron to update the statistically adjusted end use data from the US Energy Information Administration.

The Residential forecast is validated through a comparison of weather-normalized actual energy sales to forecast energy sales. Validation is also performed through statistical analysis on individual independent variables and collectively as a whole on the model.

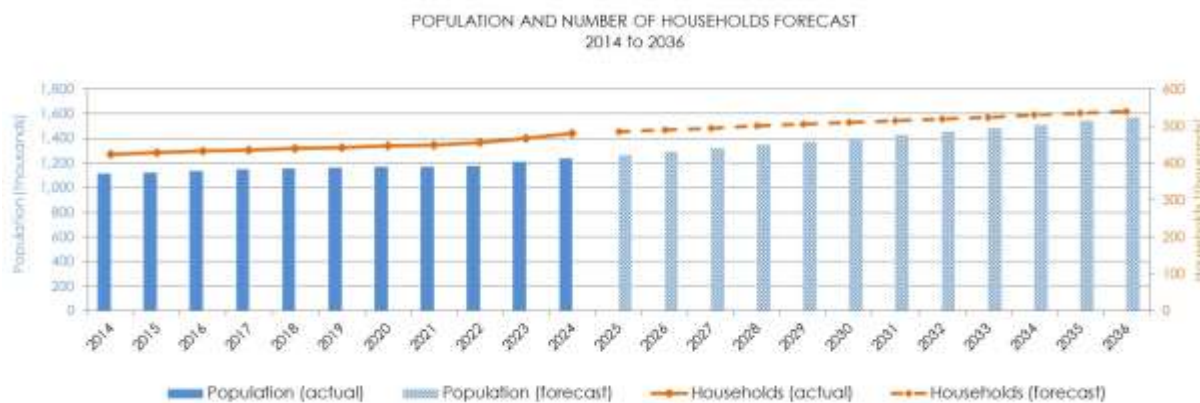
ASSUMPTIONS

- Electrical usage for residential customers assumes normal daily weather conditions based on a fifteen-year average.
- Energy efficiency standards used in the forecast are a criterion set by regulatory boards, which must be met by all electrical appliance manufacturers.
- SaskPower will maintain its current customer base and market share, except where self-generation replaces SaskPower as the supplier.

POPULATION AND HOUSEHOLD FORECASTS

The population and household forecasts are provided internally and levelized for forecasting purposes. The forecasts predict stable growth over

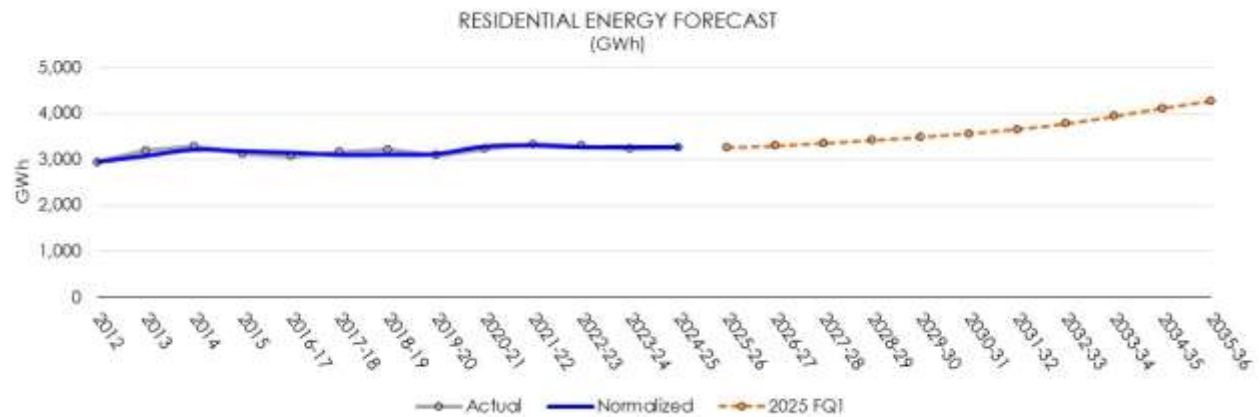
the 10-year horizon, with population and households growing at average annual rates of 2.0% and 1.0%, respectively.



RESIDENTIAL ENERGY FORECAST

The energy sales forecast for the residential class is expected to grow from 3,252.9 GWh in 2025-26 to 4,267.8 GWh in 2035-36. This total growth of 1,014.9 GWh equates to an average annual growth rate of 2.8% over the 10-year period (Refer to **Table A1**). This growth is primarily due to an increase in the UPC which are growing at a rate of 1.8% per year.

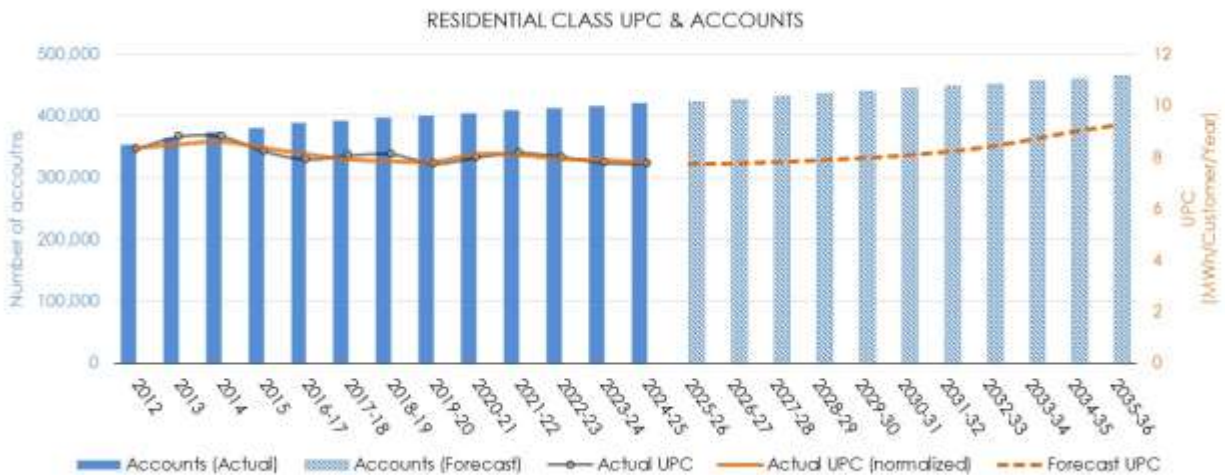
In the past 10 years, sales for the residential class have decreased by 33.6 GWh. This represents a - 0.1% average annual decrease from 2014 to 2024-25. Residential class growth reflects the province's overall population growth.



RESIDENTIAL USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts an increase in the total number of residential accounts of 41,735 over the next 10 years. This increase from 422,075 in 2025-26 to 463,810 in 2035-36 results in an average annual growth rate of 0.9% over the 10-year period. The historical average annual growth rate was 1.2% from years 2014 to 2024-25.

UPC is expected to increase from 7.7 MWh to 9.0 MWh per year over the forecast horizon as EVs are expected to become more prevalent over time. An increased emphasis on net metering activity is also expected, reducing residential energy sales by 96.1 GWh by 2035-36.



CHANGES FROM PREVIOUS FORECAST

The 2024-25 annual residential forecast is projected to average 153 GWh/year (4.1%) lower than the previous forecast over the 10-year horizon.

Forecasted account growth is 1.3% lower than the previous forecast, translating into an average

annual decrease of 5,849 accounts, or 49 GWh/year. UPC is lower than the previous forecast on average due to the change in the electric vehicle forecast. These changes in UPC result in an average annual energy decrease from the previous forecast of approximately 103 GWh/year.

RESIDENTIAL FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	UPC	Difference			%
				Customer	Total		
2025-26	3,253	3,289	-28	-8	-36		-1.1%
2026-27	3,291	3,346	-39	-16	-55		-1.7%
2027-28	3,347	3,425	-53	-24	-77		-2.3%
2028-29	3,411	3,524	-80	-32	-113		-3.3%
2029-30	3,481	3,627	-105	-41	-145		-4.2%
2030-31	3,559	3,739	-130	-50	-179		-5.0%
2031-32	3,654	3,873	-158	-61	-219		-6.0%
2032-33	3,775	4,015	-167	-72	-240		-6.4%
2033-34	3,935	4,171	-152	-84	-236		-6.0%
2034-35	4,116	4,345	-130	-98	-229		-5.6%
Average	3,582	3,735	-104	-49	-153		-4.3%
Total	35,823	37,353	-1,043	-487	-1,529		-4.3%

FARM FORECAST DETAILS



DEFINITION

A farm customer includes any rural land holding, located outside the corporate limits of a city, town, village or within the boundaries of an area legally zoned for agricultural use, where the use

and development of the land holding is exclusively for purposes of agricultural production, including irrigation loads up to 3,000 kVA.

METHODOLOGY

The forecasted number of farm customers is developed by using the historic number of farms, which is obtained from internal data sources. The future number of farm operations is forecasted using a regression model with farm households as the main variable. Farm household energy use is forecast in a comparable way to Residential household energy. Energy consumption for

irrigation is calculated based on the number of services and the average use per service. The farm forecast is validated through a comparison of weather-normalized actual energy sales to forecast energy sales. The farm forecast is also validated through individual variable and model statistics.

ASSUMPTIONS

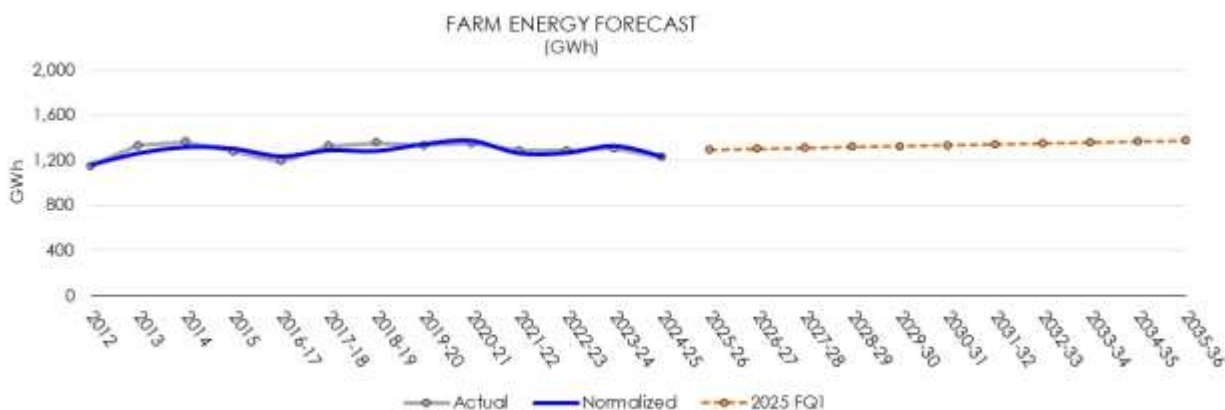
- The electrical usage for farm customers assumes fifteen-year average weather conditions.
- SaskPower will maintain its current customer base and market share, except

where self-generation replaces SaskPower as the supplier.

FARM ENERGY FORECAST

Energy sales for the farm class are expected to increase from 1,289.8 GWh in 2025-26 to 1,374.3 GWh in 2035-36 (Refer to **Table A1**). This increase of 84.5 GWh equates to an annual growth rate of 0.6%. Farm loads are expected to increase over the forecast horizon as end uses other than

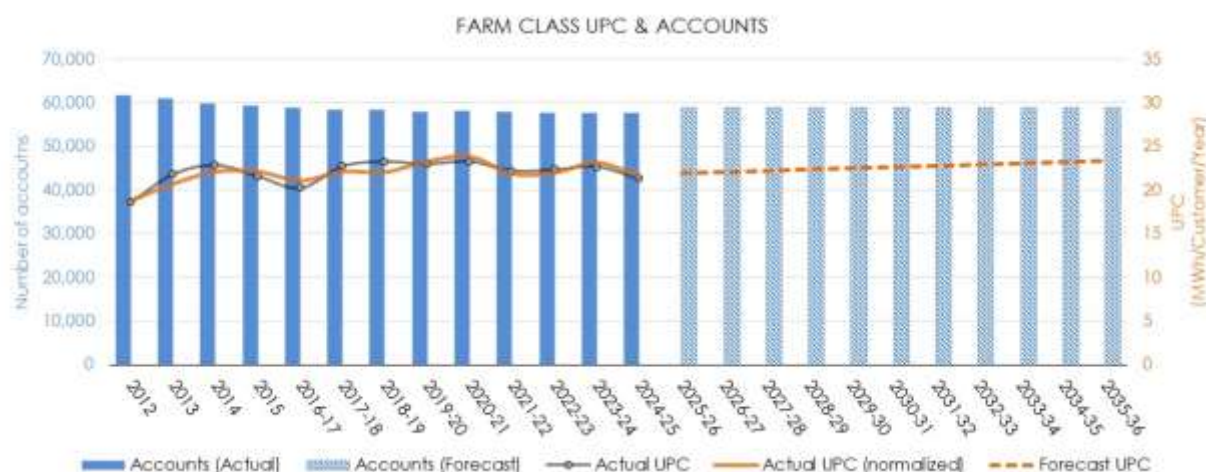
cooling and heating increase. Annual farm class energy sales have decreased between 2014 and 2024-25 by 137.7 GWh or -1.1% per year over this period and were impacted by the unusually chilly weather in 2014.



FARM USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts a decrease of 26 farm accounts over the next 10 years. Total farm accounts decrease from 58,788 in 2025-26 to 58,762 in 2035-36, which translates into an

average annual decline of 0.004% over the 10-year period. The historical average annual growth rate was -0.4% from 2014 to 2024-25. UPC increases from 21.9 MWh/per year to 23.4 MWh/per year.



CHANGES FROM PREVIOUS FORECAST

The average annual energy requirements for the farm class are projected to be 23 GWh/year higher than the previous forecast. Anticipated energy usage is expected to remain higher than the previous forecast over the majority of the entire 10-year horizon. The number of customers is higher as compared to last year's forecast by an

average of 869 customers/year which increases the energy sales by an average of 20 GWh/year. UPC is anticipated to remain steady at 22.6 MWh/customer throughout the forecast period. On average, UPC contributes 4 GWh/year to the increase in annual energy use compared to last year's forecast.

FARM FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	UPC	Difference			%
				Customer	Total		
2025-26	1,290	1,312	-27	5	-22		-1.7%
2026-27	1,299	1,309	-21	10	-10		-0.8%
2027-28	1,307	1,308	-14	13	-1		-0.1%
2028-29	1,317	1,307	-6	16	10		0.8%
2029-30	1,325	1,305	1	18	20		1.5%
2030-31	1,332	1,302	9	21	31		2.3%
2031-32	1,340	1,300	16	24	40		3.0%
2032-33	1,348	1,301	20	27	47		3.5%
2033-34	1,357	1,301	26	30	56		4.1%
2034-35	1,366	1,302	31	33	64		4.7%
Average	1,328	1,305	4	20	23		1.8%
Total	13,280	13,046	37	198	234		1.8%

RESELLER FORECAST DETAILS



- SaskPower's wholesale electricity customers
- Forecast typically provided by the customers themselves
- Cities of Swift Current and Saskatoon operate independent municipal utilities within their franchise areas
- Only 3 Customers

DEFINITION

The reseller class includes customers who purchase bulk power from SaskPower and distribute electricity to residential and commercial

customers within their districts. SaskPower serves two reseller customers, the cities of Saskatoon and Swift Current.

METHODOLOGY

SaskPower meets with both reseller customers to discuss their estimates of future load growth. An individual forecast is developed for each customer, which are then combined into a total reseller class forecast.

To validate the reseller class forecast, the forecasted energy sales are compared to historical sales trends.

ASSUMPTIONS

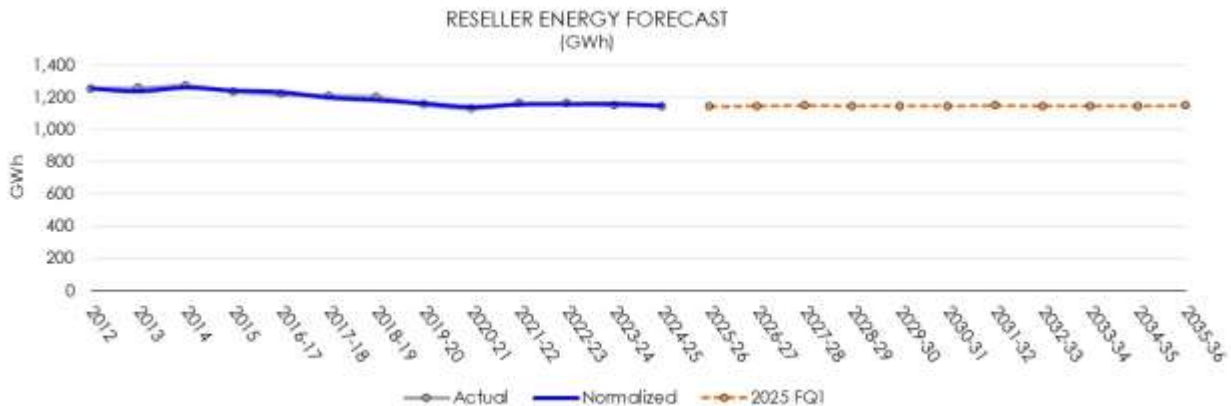
- Normal daily weather conditions are based on a thirty-year average.
- SaskPower will maintain its current customer base and market share,

except where self-generation replaces SaskPower as the supplier.

RESELLER ENERGY FORECAST

Saskatoon and Swift Current's opportunities for load growth are limited as they are constrained by their municipal franchise boundaries. As such, annual reseller class energy sales are expected to

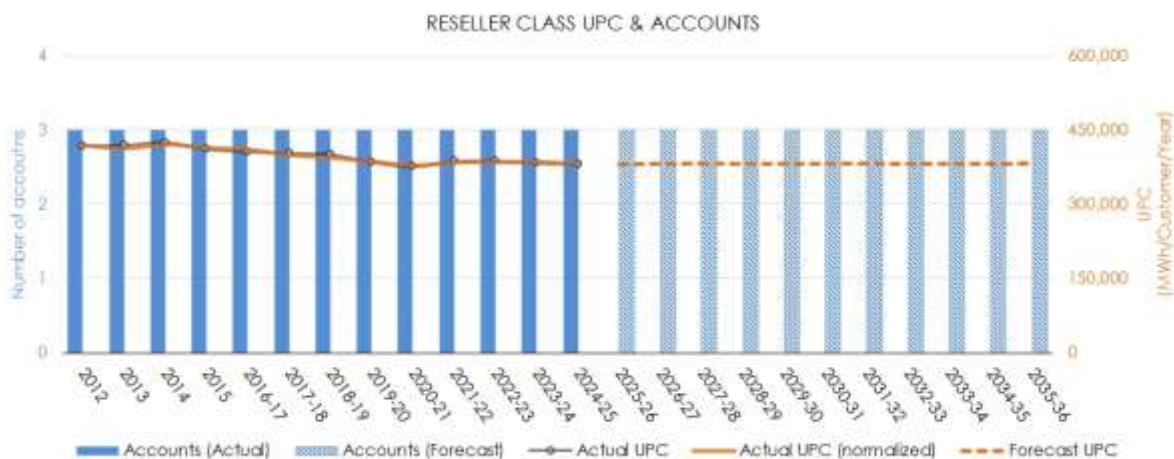
grow slightly from 1,140.0 GWh to 1,148.7 GWh over the 10-year horizon, or 0.04% per year. Reseller sales have decreased 1.1% annually from 2014 to 2024-25.



RESELLER USE PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts the total number of reseller accounts will remain the same over the 10-year horizon. UPC is expected to rise

slightly from 380,009 MWh to 382,916 MWh per year.



CHANGE FROM PREVIOUS FORECAST

Latest information from the reseller customers has resulted in a lower annual energy forecast of 51 GWh/year for this class from the 2024-25 Q1

forecast. As the number of customers remains unchanged, a decrease in UPC is the driver for the lower forecast.

RESELLER FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	UPC	Difference		
				Customer	Total	%
2025-26	1,140	1,183	-43	0	-43	-3.8%
2026-27	1,146	1,185	-39	0	-39	-3.4%
2027-28	1,149	1,190	-41	0	-41	-3.6%
2028-29	1,146	1,189	-43	0	-43	-3.8%
2029-30	1,146	1,192	-46	0	-46	-4.0%
2030-31	1,146	1,195	-50	0	-50	-4.3%
2031-32	1,149	1,203	-54	0	-54	-4.7%
2032-33	1,146	1,205	-59	0	-59	-5.2%
2033-34	1,146	1,211	-66	0	-66	-5.7%
2034-35	1,146	1,220	-74	0	-74	-6.5%
Average	1,146	1,197	-51	0	-51	-4.5%
Total	11,457	11,971	-515	0	-515	-4.5%

SYSTEM LOSSES, UNACCOUNTED ENERGY FORECAST (UFE) & EXPORT DETAILS



- Transmitting and distributing electricity results in some losses along the way.
- Losses are classified as transmission or distribution depending on the line voltage being examined.
- Losses are merely the difference between total energy generated and energy sold.

DEFINITION

This category is comprised of transmission and distribution losses and unmetered corporate and customer electric energy use which includes all switching stations, distribution substations, station service and grid transformer losses.

Transmission losses are incurred when transmitting power from the generating stations to the distribution facilities — typically the high voltage side of 138kV to 25kV or 72kV to 25kV substations — and includes all 230kV, 138kV and 72 kV transmission lines. Distribution losses are the losses incurred between the distribution facilities, including all distribution lines and substations (below 66kV), and the customers' meters.

There are four types of losses³:

- 1) **Technical:** the difference between the energy injected into a network and the energy delivered to points of connection.
- 2) **Non-Technical:** the difference between the volume of energy conveyed at points

of connection and the volume of energy reported as conveyed at the same points of connection. This type includes theft, metering errors, billing timing, and data handling errors.

- 3) **Reconciliation:** the difference between reported energy injected into a network and the reported energy extracted from the network. Reconciliation loss is the combination of technical and non-technical.
- 4) **Unaccounted for Electricity:** this is calculated from the difference between reported energy injected into a network and the reported energy extracted from the network after it has been adjusted for losses.

As of 2021-22, the system losses forecast no longer includes an estimation for export energy sales.

³ <https://www.ea.govt.nz/operations/distribution/losses>

METHODOLOGY

Extrapolation techniques as well as a loss estimation tool are used to predict the future energy losses due to transmission, distribution system losses and unmetered use.

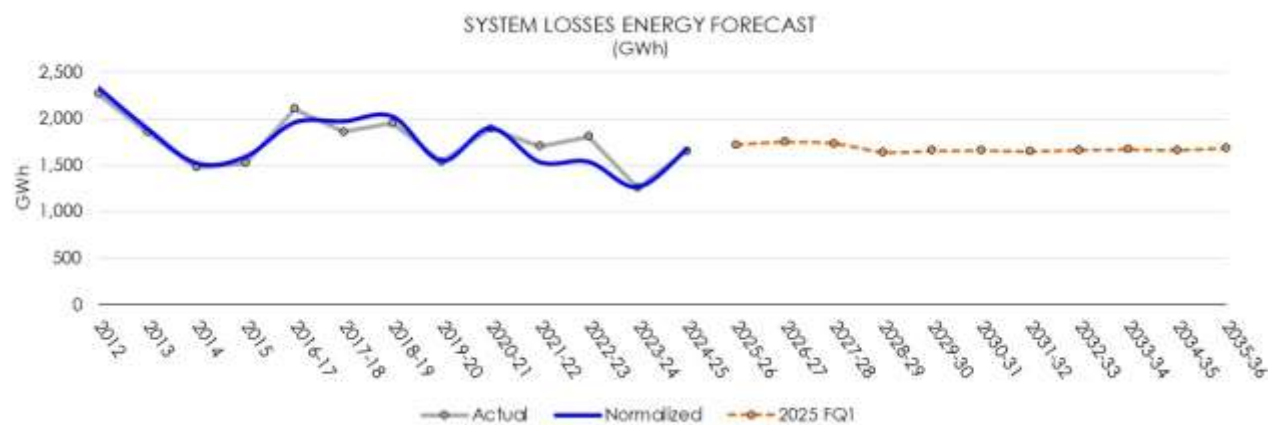
Distribution losses are estimated using an historical average percent of distribution sales applied to

future distribution sales. The method used to estimate unaccounted energy usage is the same as used for estimating distribution losses. A comparison of historical actual to forecast energy consumption is used to validate the losses and unaccounted forecast.

LOSSES AND UNACCOUNTED ENERGY FORECAST

Losses and unaccounted energy are expected to decrease from 1,723.2 GWh in 2025-26 to 1,686.3 GWh in 2035-36 (Refer to **Table A1**). This 36.8 GWh decrease translates into an average annual rate

of -0.2%. Losses and unaccounted energy have increased at an average annual rate of 1.2% over the past 10 years.



CHANGE FROM PREVIOUS FORECAST

For the 2025-26 Q1 forecast, an official estimate of transmission losses was unavailable prior to the forecast being published. In this case an historic percentage was used for transmission losses. The

implicit inclusion of exports was removed from the calculation to model the true losses more accurately.

SYSTEM LOSSES FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	Difference	%
2025-26	1,723	1,626	97	6.0%
2026-27	1,749	1,655	94	5.7%
2027-28	1,735	1,687	48	2.8%
2028-29	1,645	1,718	(74)	-4.3%
2029-30	1,658	1,722	(64)	-3.7%
2030-31	1,662	1,709	(48)	-2.8%
2031-32	1,652	1,724	(72)	-4.2%
2032-33	1,666	1,731	(64)	-3.7%
2033-34	1,672	1,718	(46)	-2.7%
2034-35	1,666	1,730	(64)	-3.7%
Average	1,683	1,702	(19)	-1.1%
Total	16,828	17,020	(193)	-1.1%

0.

EXPORTS

Exports represent the sale of SaskPower's available generation to other regions in Canada and the United States and are dependent on the availability of SaskPower generation, market conditions in other jurisdictions and transmission availability.

SaskPower maintains interconnections with Alberta, Manitoba, and North Dakota that have the following capacity under normal system conditions: 350 MW from Manitoba, 147 MW from Alberta and 150 MW from North Dakota.

The model incorporates the latest load forecast and load shapes, in addition to inputs such as forecasted natural gas prices, market prices, unit maintenance, forced outages, and unit operating characteristics and constraints. The export forecast developed using this methodology is considered "non-firm." Therefore, it is not incorporated into SaskPower's capacity planning and forecasted export energy sales are not included in this report.

NON-GRID FORECAST DETAILS



- SaskPower's non-grid system is that which is not connected to the main grid
- Sales in this sector are generated by diesel or refer to purchased power from Manitoba Hydro
- Only 4 communities make up this sector

DEFINITION

The non-grid forecast represents energy sold to customers in communities who do not have access to SaskPower's electrical grid. These communities include **Kinoosao, Creighton, Sturgeon Landing** and **Denare Beach**. The energy sold to these communities comes from the

Kinoosao diesel plant and through power purchases from Manitoba Hydro. The customers in these communities are classified as Residential, Commercial, or Corporate Use. The non-grid forecast also includes distribution system losses incurred serving these communities.

METHODOLOGY

Extrapolation is used for predicting the future use per customer and the number of customers. To

validate the non-grid forecast a comparison of historical to forecast consumption is made.

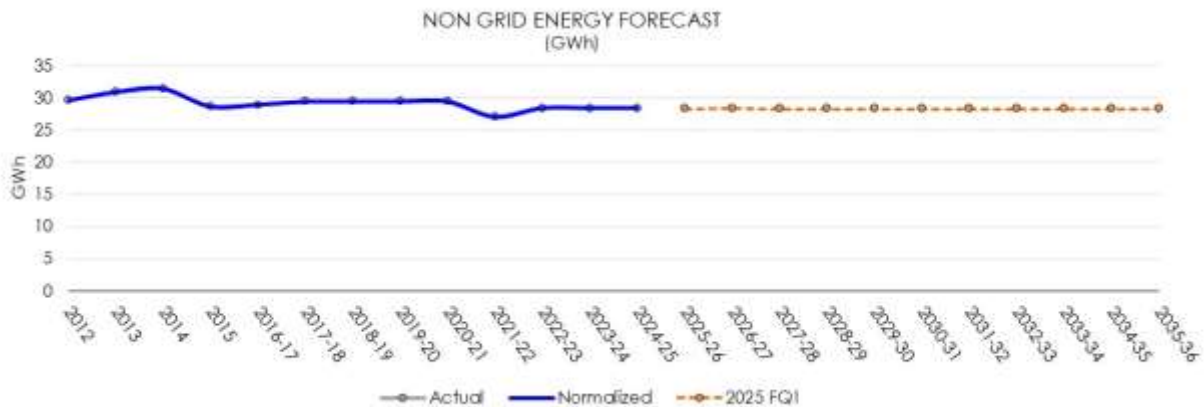
ASSUMPTIONS

- Customers do not have access to natural gas in northern Saskatchewan and are fully electrified.
- SaskPower will maintain its current customer base and market share, except where self-generation replaces SaskPower as the supplier.

NON-GRID ENERGY FORECAST

The energy requirements for non-grid customers are expected to remain at 28.5 GWh from 2025-26 and into the future. (Refer to **Table A3**). The

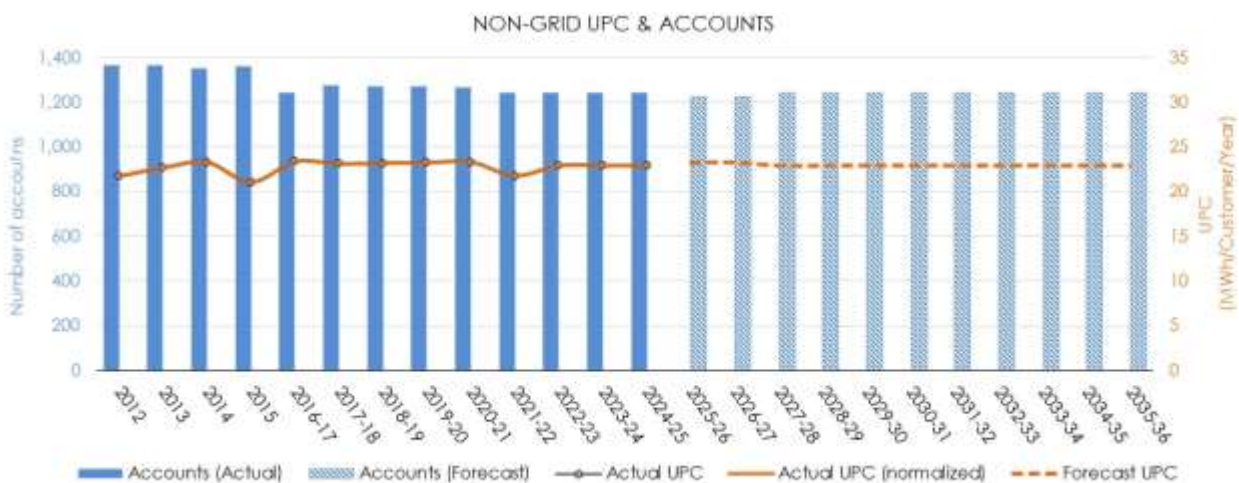
number of customers is forecasted to increase from 1,226 in 2025-26 to 1,242 in 2035-36 in the Residential sector.



NON-GRID PER CUSTOMER (UPC) AND NUMBER OF ACCOUNTS

The 2025-26 Q1 load forecast predicts the total number of non-grid accounts will increase by 16 from 2025-26 Q1 to 2035-36 Q1 and UPC will

decrease from 23.2 MWh in 2025-26 Q1 to 22.9 MWh in 2035-36 Q1.



CHANGE FROM PREVIOUS FORECAST

The average annual energy requirements for non-grid customers are projected to be 1 GWh/year lower than the previous forecast. Anticipated energy usage is expected to remain lower than the previous forecast over the entire 10-year horizon. The number of customers is higher as compared to last year's forecast by an average

of 1 customer/year which has virtually no impact on energy sales. UPC is anticipated to decrease from 23.5 MWh/customer in the previous forecast to 23.0 MWh/customer. On average, UPC contributes 1 GWh/year to the decrease in annual energy use compared to last year's forecast.

NON-GRID FORECAST (GWH)

Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	Difference			
			UPC	Customer	Total	%
2025-26	28	29	0	-0.3	-0	-1%
2026-27	28	29	0	-0.3	-0	-1%
2027-28	28	29	0	0.1	0	0%
2028-29	28	29	0	0.1	0	0%
2029-30	28	29	0	0.1	0	0%
2030-31	28	29	0	0.1	0	0%
2031-32	28	29	0	0.1	0	0%
2032-33	28	29	0	0.1	0	0%
2033-34	28	29	0	0.1	0	0%
2034-35	28	29	0	0.1	0	0%
Average	28	29	-1	0.0	-1	-2%
Total	285	291	-6	0.2	-6	-2%

SYSTEM PEAK DEMAND FORECAST DETAILS



- Multiple ways of evaluating Peak load (instantaneous, interval, potential, most likely, etc.)
- SaskPower is a winter peaking utility, meaning our highest system demand occurs in the winter months from October to February

DEFINITION

The system peak demand represents the highest level of demand placed on the supply system at any time during the year. SaskPower generates both potential and most likely peak demand forecasts for planning and costing purposes, respectively.

Potential system peak demands represent the highest level of demand placed on the supply system at any time during the year if typical lighting loads occur and all large consumers are operating at their normal levels under below average weather conditions. Potential peaks are used for SaskPower's planning purposes and represent the maximum demands SaskPower

must be prepared for if all these conditions are met.

The **Most Likely** system peak demand forecast represents the highest level of demand placed on the supply system at any time during the year if typical lighting loads occur and all large consumers are operating at their normal levels under five-year average weather conditions.

The system peak has historically occurred on a weekday evening during the winter months and is important for planning purposes because SaskPower must have adequate generation and transmission capacity available to supply the system peak demand.

METHODOLOGY

SaskPower forecasts instantaneous as well as hourly interval system peak demands. Instantaneous peak demand is the maximum

system demand at the instant of greatest load, while the interval peak demand is the maximum

system demand averaged over a given period (i.e., 60 minutes).

The factors that contribute to the peak load include time of day, seasonal variations, industrial load, and weather conditions. Seasonal variations include Christmas lighting, increased lighting load due to shorter daylight hours and increased shopping hours. Historically, the peak load has occurred during the heating season months of November, December, January, and February. SaskPower forecasts a potential system peak demand which requires sustained wintry weather during the month of December prior to the Christmas vacation period.

Historical and current sales forecast data is used to develop an hourly interval coincident peak load factor for each power class and large oilfield customer. This information, along with information obtained during discussions with each customer regarding anticipated changes in operations, is used to develop an hourly interval peak demand forecast for each power class and large oilfield

customer. The hourly interval peak forecast for all other customer classes is estimated using coincident peak load factors developed from SaskPower's interval meter load research. This load research relates customer class historic contribution to the system peak demand to annual energy sales. The hourly interval system peak load forecast is determined by adding the hourly interval peak load for each class and the instantaneous system peak load is calculated using the historic relationship between the hourly interval and instantaneous peak demand.

Three approaches are used to validate the system peak demand forecast. Historical peak load is compared to forecast peak load, forecasted peak load is compared to historical system peak loads normalized for weather conditions, and the historical load factor is compared to forecasted future system load factor.

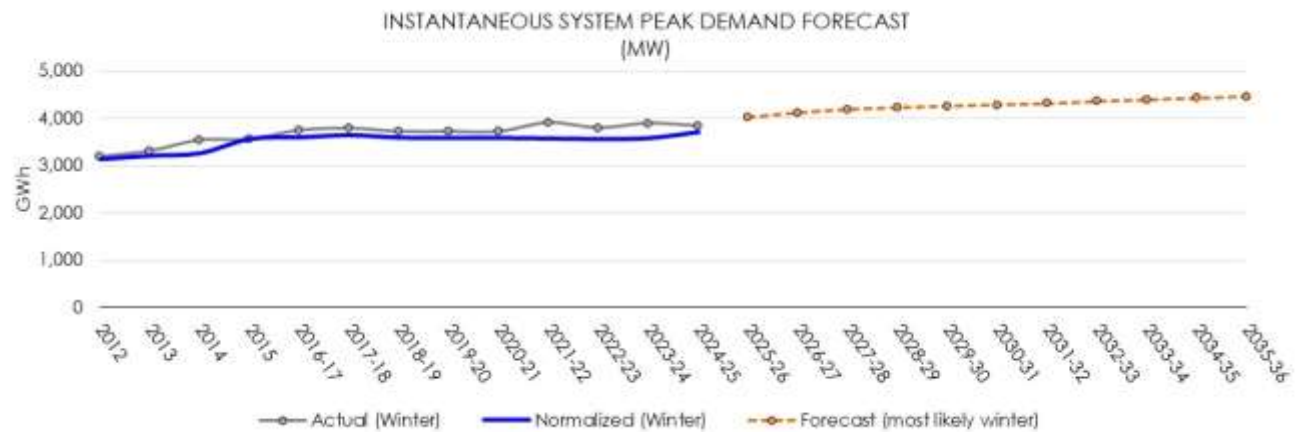
ASSUMPTIONS

- Apart from power accounts and large oilfield customers, all customer classes use hourly interval coincident peak load factors from SaskPower's load research.
- Five-year historical average data is used for each power and large oilfield customer, when applicable, to determine their hourly interval coincident peak load factor.
- For customers who have not been in existence for this period, the most recent history is used or a coincidence factor from a similar customer is assumed.
- If necessary, outliers are ignored for the purposes of calculating an average Coincident Peak load factor.

POTENTIAL & MOST LIKELY PEAK FORECAST

The instantaneous potential system peak load is expected to grow from 4,103 MW in 2025-26 to 4,553 MW by 2035-36, resulting in an average annual growth rate of 1.1%. The 2025-26 instantaneous most likely system peak load is expected to reach 4,018 MW and increase to 4,459 MW by 2035-36 (Refer to **Table A4**). This 441

MW increase, results in an average annual growth rate of 1.1%. The system peak load has increased at an annual rate of 0.8 % over the last 10 years. Forecasted growth is largely attributed to the expected increases in the residential, power, commercial, and oilfield classes.



CHANGE FROM PREVIOUS FORECAST

The changes in forecast peak demand, both for potential and most likely, is partially attributable to load factor adjustments made due to updated historic peak load factors from load research.

There is also an impact from the higher energy forecast, as peak is derived directly from energy. Any increase in the implementation of self-generation partially offsets the growth in the peak.

MOST LIKELY INSTANTANEOUS PEAK FORECAST (GWH)

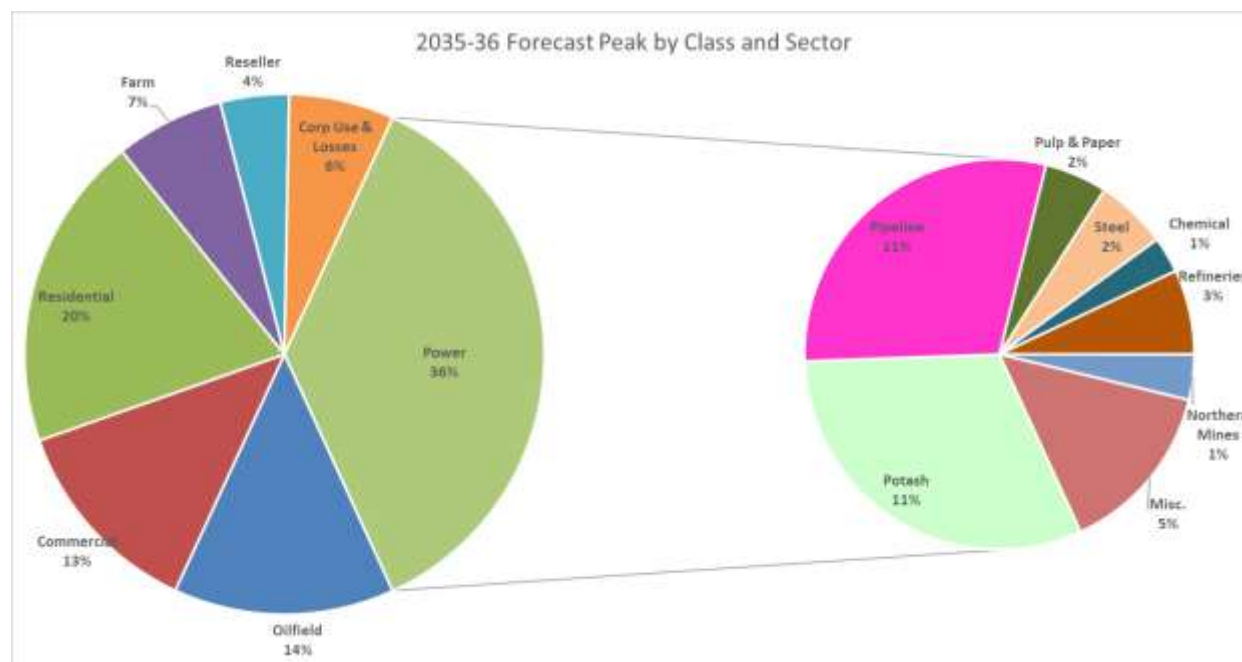
Comparison of 2026 FQ1 forecast to 2025 FQ1 Forecast

Fiscal Year	2026 FQ1	2025 FQ1	Difference	%
2025-26	4,018	3,983	34	0.9%
2026-27	4,115	4,093	23	0.5%
2027-28	4,189	4,219	(30)	-0.7%
2028-29	4,226	4,271	(45)	-1.1%
2029-30	4,258	4,312	(54)	-1.2%
2030-31	4,287	4,333	(46)	-1.1%
2031-32	4,313	4,366	(54)	-1.2%
2032-33	4,358	4,396	(38)	-0.9%
2033-34	4,395	4,441	(46)	-1.0%
2034-35	4,428	4,487	(58)	-1.3%
Average	4,259	4,290	(31)	-0.7%
Total	42,588	42,902	(314)	-0.7%

PEAK FORECAST BY CUSTOMER CLASS

The most likely system peak forecast by customer class and sector over the 10-year forecast horizon is shown in the figures below. The power class is projected to account for 36% (1,619 MW) of the total system peak by 2035-36, with residential (20%,

875 MW), commercial (13%, 567 MW) and oilfield (14%, 613 MW) classes accounting for the bulk of the remainder. The full 10-year breakdown can be found in the graphs below.



2025-26 Q1 LOAD FORECAST – CUSTOMER CLASS MOST LIKELY PEAK (MW)

Year	Power	Oilfield	Commercial	Residential	Farm	Reseller	Corp Use & Losses	Total Peak
2025-26	1,404	600	541	682	287	192	240	3,947
2026-27	1,474	607	545	690	290	194	184	3,983
2027-28	1,535	612	544	697	290	193	222	4,093
2028-29	1,598	615	541	702	289	191	283	4,219
2029-30	1,600	623	545	717	291	191	305	4,271
2030-31	1,610	626	547	732	293	191	315	4,312
2031-32	1,610	632	549	750	294	191	307	4,333
2032-33	1,620	632	554	775	297	192	298	4,366
2033-34	1,624	626	558	805	298	191	294	4,396
2034-35	1,621	620	562	845	300	191	301	4,441
2035-36	1,619	613	567	875	302	191	320	4,487
Ann. Growth	1.4%	0.2%	0.5%	2.5%	0.5%	-0.1%	2.9%	1.3%

2025-26 Q1 LOAD FORECAST – POWER CLASS SECTOR MOST LIKELY PEAK (MW)

Year	Potash	Pipeline	Pulp & Paper	Steel	Chemical	Refineries	North Mines	Misc.	Sub-Total
2025-26	371	500	86	97	49	99	52	149	1,404
2026-27	380	500	86	98	49	112	58	191	1,474
2027-28	431	496	85	97	49	111	63	202	1,535
2028-29	500	491	85	96	48	110	60	207	1,598
2029-30	507	478	84	96	48	110	62	214	1,599
2030-31	507	477	84	96	48	114	63	219	1,609
2031-32	507	477	84	96	48	114	61	222	1,610
2032-33	508	478	85	96	48	114	63	227	1,620
2033-34	507	477	84	96	48	114	62	235	1,624
2034-35	507	477	84	96	48	114	61	234	1,621
2035-36	506	476	84	96	48	114	61	233	1,619
Ann. Growth	3.2%	-0.5%	-0.2%	-0.2%	-0.2%	1.4%	1.5%	4.5%	1.4%

SUMMARY OF FORECAST DETAILS

OVERVIEW

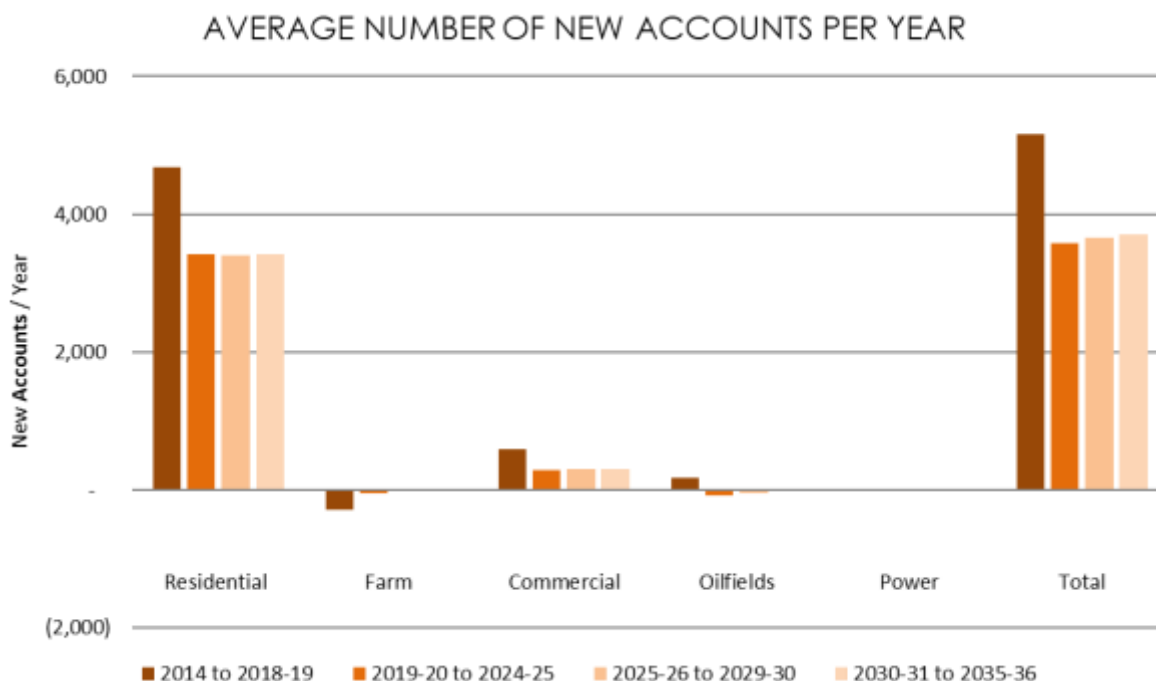
The tables below provide the average number of new accounts per year as well as the average energy sales growth per year over the following

periods: Actual loads for the years 2014-2018 to 19, 2019-20 to 2024-25, and forecasted loads for 2025-26 to 2029-30 as well as 2030-31 to 2035-36.

CUSTOMER GROWTH

The average number of accounts and energy sales growth from 2014-2018-19 was typical. Oilfield energy growth was strong over this period, resulting in a significant increase in customers. The population of Saskatchewan increased over this

period as well, resulting in the residential customer growth. The reduction in farm customers is expected as the size of farm operations trend larger.



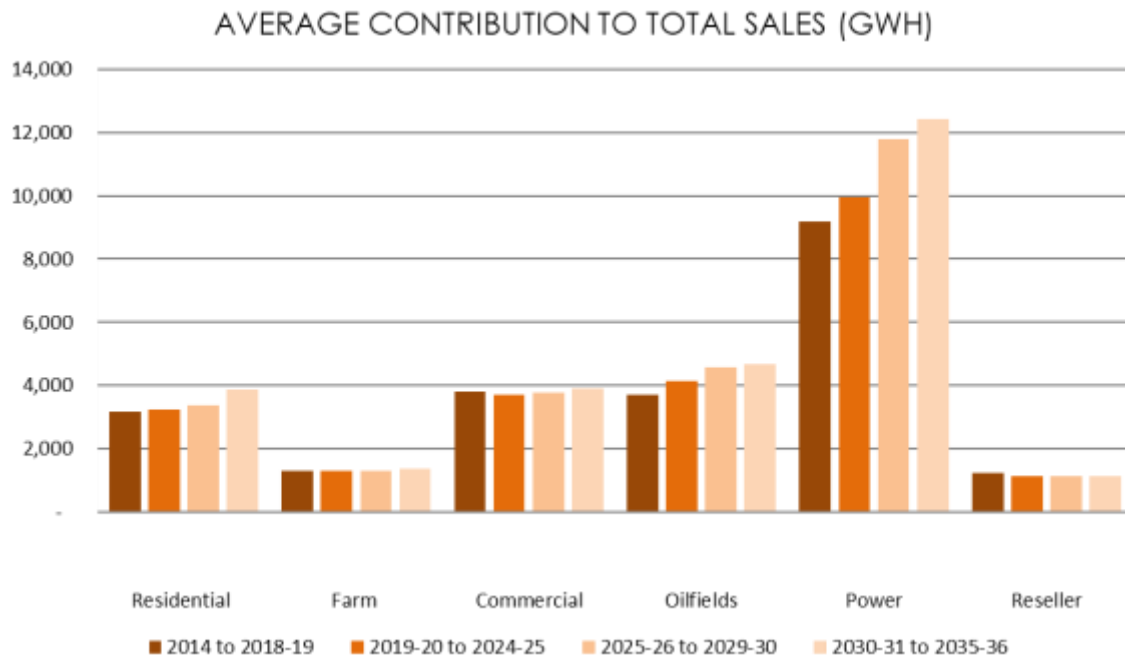
ENERGY GROWTH

The exceptional level of economic activity in Saskatchewan between 2012 and 2016 led to an increased number of accounts and combined with the unusually cold winters in 2013 and 2014,

resulted in a substantial increase in energy sales growth. Oilfield energy sales continued to be strong, and the Power class growth recovered from the recession to provide strong gains,

particularly in the pipeline pumping, potash, and northern mines sectors. The average number of accounts and average contribution to total sales by class from 2025-26 to 2029-30 reflect an expected future increase in the population of the province. Oilfield, Power, and Commercial classes lead the way in average contribution to total sales

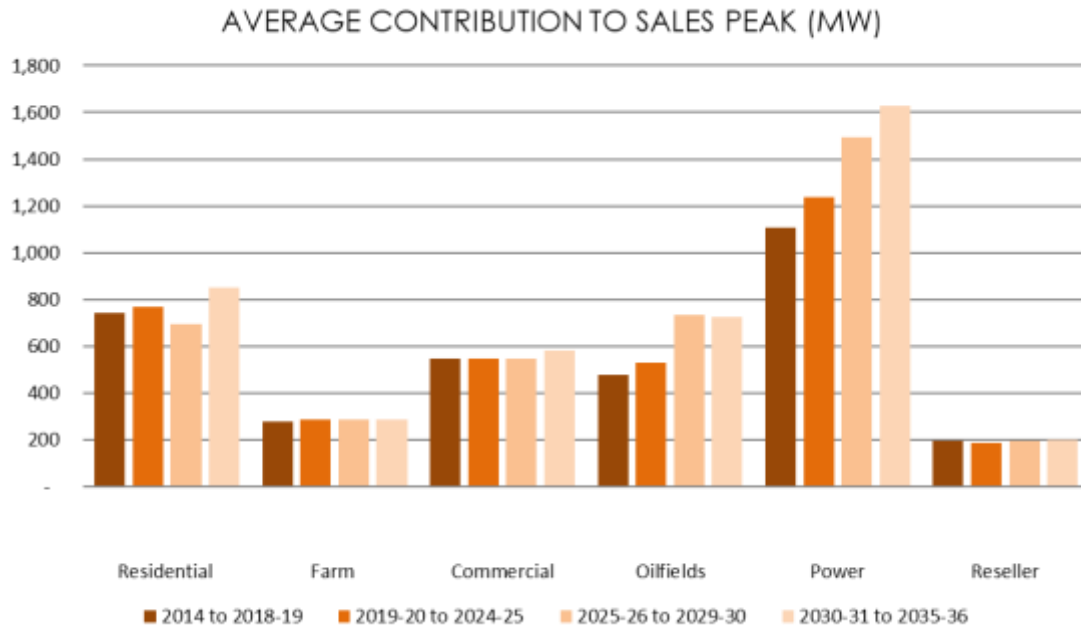
in the forecast period. The oilfield production forecast is largely like the last iteration. It is expected that oilfield energy sales will remain strong as aging oilfields require more energy to extract the remaining oil. Power class sales are expected to remain strong throughout the forecast period.



CONTRIBUTION TO PEAK

The average contribution to peak by sales class illustrates how most classes are increasing except for the Farm and Reseller classes. Reseller customers are bound in large part by their

franchise areas. In the Farm class, the stagnant energy growth is causing the lack of growth in average contribution to sales peak.



LOAD FORECAST UNCERTAINTY



- Load Forecast uncertainty refers to the likelihood that actual load will come in differently than the forecast.
- The goal is to minimize the error to the extent possible.
- The high/low provides a band within which we are highly confident the actuals will fall

HIGH/LOW FORECAST

DEFINITION

The energy and system peak load forecasts developed above reflect a most likely scenario of economic and weather conditions, meaning there is a 50% chance the actual results will be either higher or lower than the reported forecast. A degree of uncertainty is inherent in most long-term forecasts since they are based on numerous

assumptions and input variables that will vary in the short and long-term. For this reason, a high and a low scenario forecast is developed for both energy and peak demand. These scenarios cover possible ranges in economic variations and other uncertainties.

METHODOLOGY

Independent economic data is a major driver in the development of the 2025-26 Q1 most likely load forecast. An actual course of economic development for Saskatchewan that deviates from the forecast would have an impact on energy consumption. The 2025-26 Q1 load forecast was also based on a fifteen-year average weather pattern. Deviation from this weather pattern will also impact energy consumption.

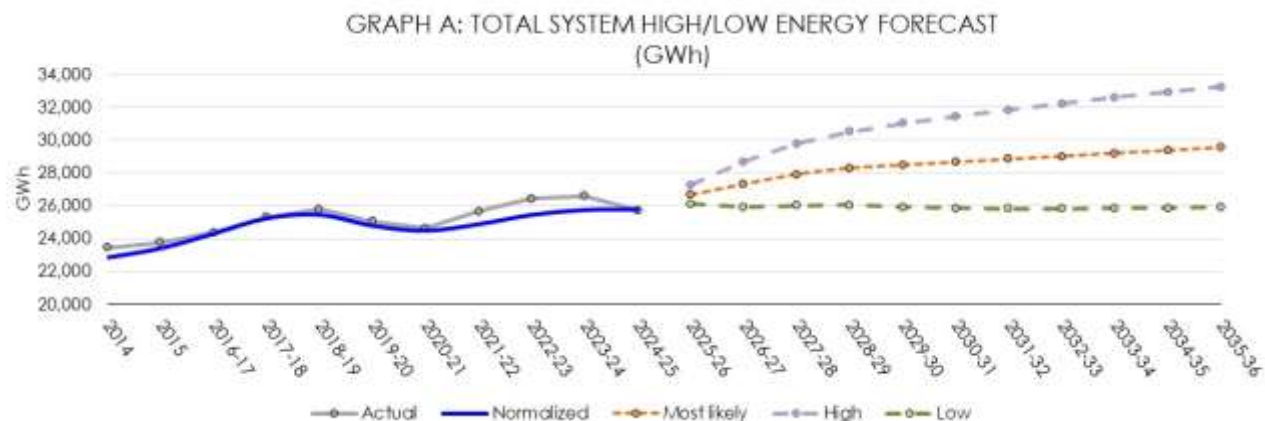
To reflect the economic and weather uncertainties, grid high and low energy

consumption and system peak demand forecasts are developed using a Monte Carlo simulation model. This model uses the percentage error by customer class in year 1, year 2, year 3, etc., of previous forecasts. The forecast error for each class is considered to have a normal distribution and to be independent from the forecast error of other classes. The high / low forecast results are developed using a 90 percent confidence interval meaning that there is 90% probability that future energy and peak demand loads will fall within the bounds created by the high and low load forecasts.

HIGH - LOW FORECAST RESULTS

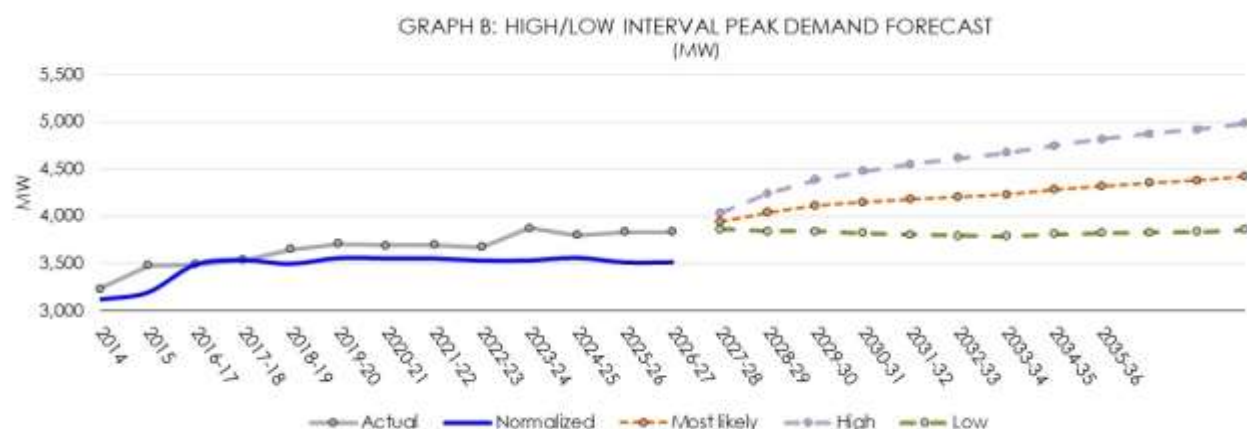
In relation to the 2025-26 Q1 most likely forecast, the high forecast scenario for total energy requirements and most likely interval peak are 609.7 GWh and 89.0 MW higher, respectively. In 2035-36, the high scenario forecasts the energy to

be 3,690.4 GWh higher and the demand to be 545.1 MW higher than the most likely forecast (refer to **Graph A** for energy and **Graph B** for peak).



Relative to the most likely case, the low forecast scenario for 2025-26 Q1 total energy requirements and most likely peak are 550.7 GWh and 80.3 MW lower, respectively. In 2035-36, the low scenario

forecasts the energy to be 3,656.5 GWh lower and the peak demand to be 540.0 MW lower than the most likely forecast.



FORECAST SENSITIVITY & EXTREME EVENTS

OVERVIEW

An emerging trend in forecasting is to analyze scenarios in isolation to provide information to decision makers regarding their relative impact.

SaskPower has adopted this approach to respond to requests for specific data informed by modeling various discrete events.

ECONOMIC AND CLIMATE TRENDS

SaskPower completed the following sensitivity analysis surrounding specific economic and climate trends:

+/- % change in:	Description	Energy change (GWh)	Peak demand change (MW)
Population	Increasing and decreasing the amount of growth versus what was assumed in the SaskPower customer forecast describes what could happen if the population is lower or higher than expected.	3.8 / (3.8)	0.09 / (0.09)
Income	Adjusting the household income elasticity by 1% in either direction for all end uses demonstrates the extent to which income influences the amount of power customers will consume.	0.1 / (0.1)	0.02 / (0.01)
Price of electricity	Increasing and decreasing the price elasticity of electricity for all end uses measures the effect of reducing demand if the price of electricity is raised and increasing demand if price is decreased.	(8.8) / 8.9	(1.31) / 1.32
Temperature (°C)	The effect was modeled by re-calculating smooth normal HDDs and CDDs based on an increase and decrease of 1°C on the average dry bulb temperature. CDDs and HDDs are calculated based on the average dry bulb temperature. As SaskPower is a winter peaking utility an increase in temperature results in a reduction in load because energy demand is greater in winter. Conversely, if temperatures drop, load will increase for the same reason.	(7.8) / 14.7	(1.16) / 2.2

LOW PROBABILITY/HIGH RISK EVENTS

SaskPower performs sensitivity analysis around extreme events that have potential, however remote, of happening and may increase or decrease load on the system. All the scenarios

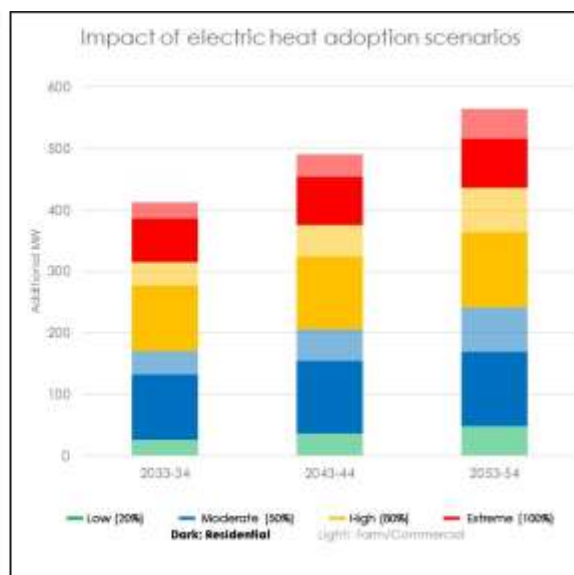
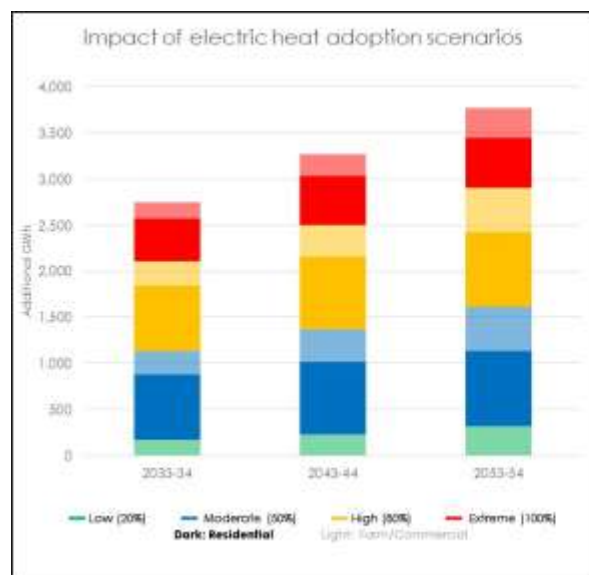
Electric Heat

There is a possibility that more customers will convert to electrical heat in the future. As part of the response to climate change there has been a push to electrify more end uses due to anticipated

examined are considered distributed energy resource events and were assessed independently of each other. The results are shown in the following sections below.

carbon decreases in electricity generation. Modelling this scenario involved utilizing the residential customer forecast and an assumption of 100% electric heat by the date specified. The

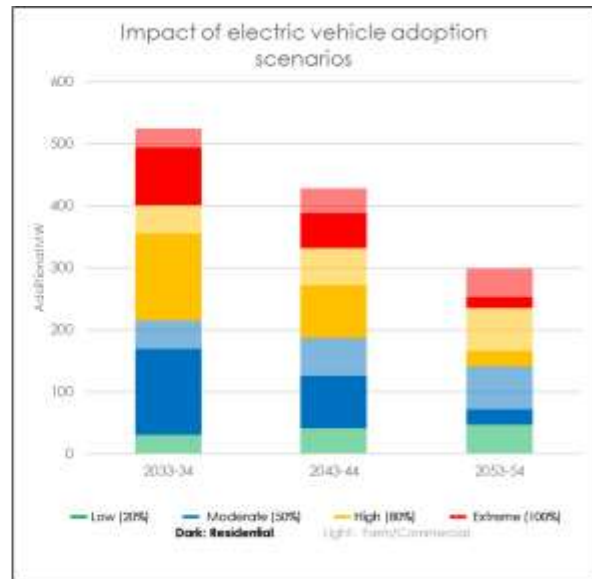
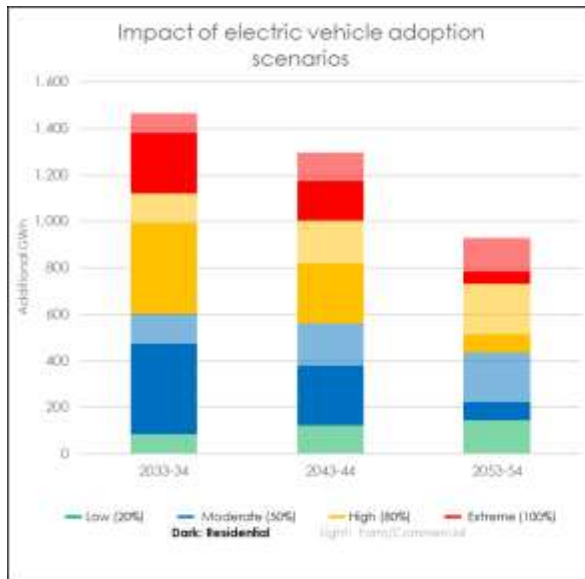
difference between the base forecast and the scenario was calculated and averaged to produce the numbers indicated in the table.



Electric Vehicles

There is potential for EV adoption to substantially increase in the future. Factors influencing adoption include the economics for EVs improving as production costs decrease, increased government grants, or penalties implemented for ICE vehicles. It may also be influenced by a reduction of range anxiety, charging stations becoming more prevalent, and

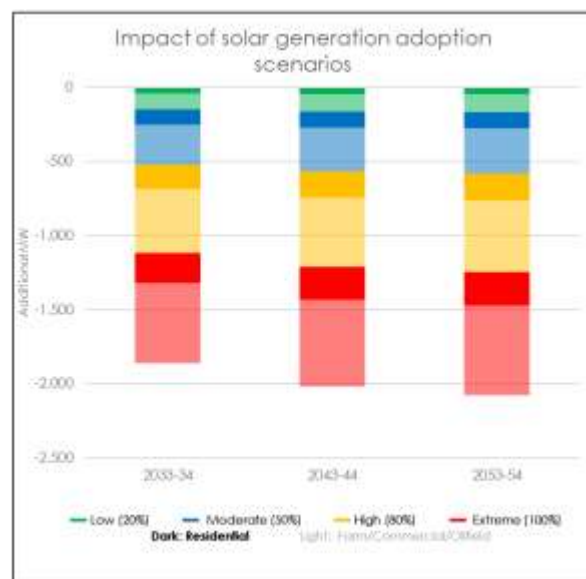
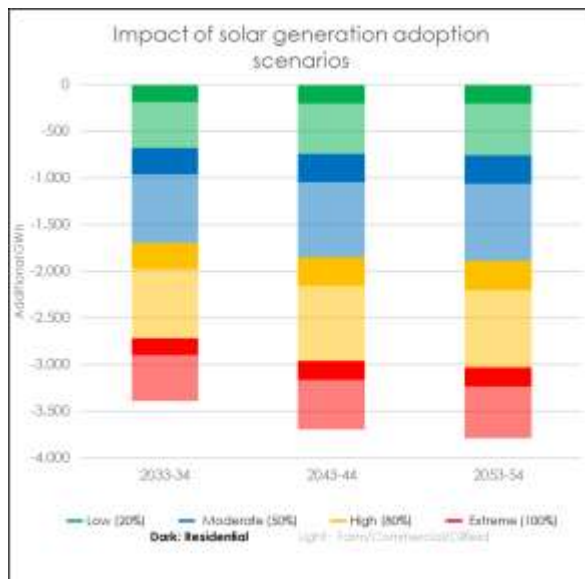
EV charge times decreasing. SaskPower modeled these scenarios by increasing the number of EVs to match the percentage and date shown in the table based on historical vehicle growth rates in Saskatchewan. The differences between the base EV forecast and the various scenarios were averaged over the forecast horizon to produce the number in the table.



Photovoltaic (Solar Generation)

Customers continue to install solar arrays under the terms of the Net Metering 2.0 contract. There is a possibility that as economies of scale are achieved that the case for self-generation will improve and be adopted to a larger extent than is forecasted. Residential, commercial, oilfield, and farm customers were used to model these

scenarios. The estimates were based on an 8kVa, 63 kVa, 221 kVa, or 19 kVa array size as indicated in the tables below. The difference is taken between the base forecast and the scenario indicated and averaged over the forecast horizon to produce the projection in the table.

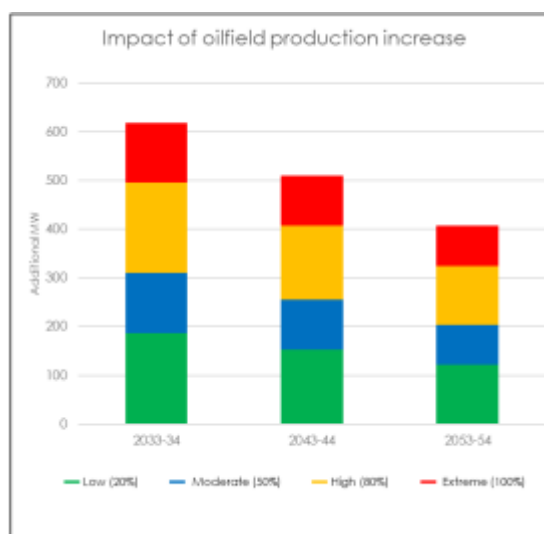
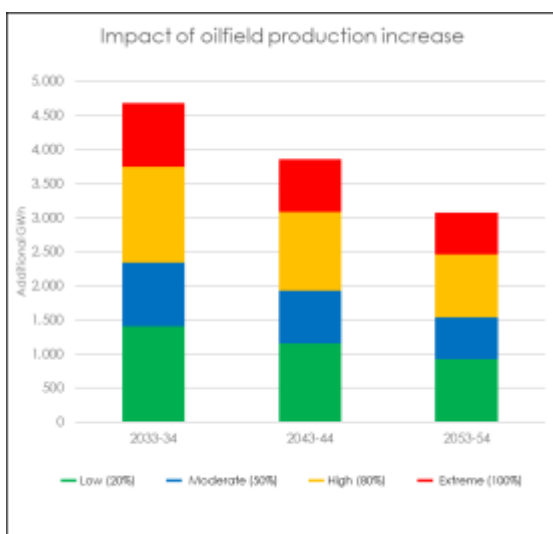


Oilfield - Production Forecast

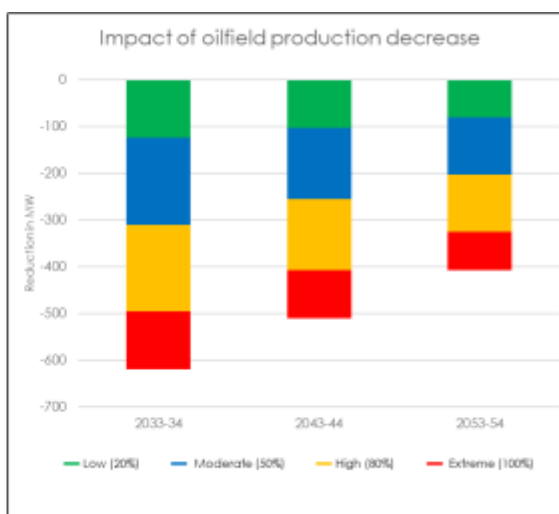
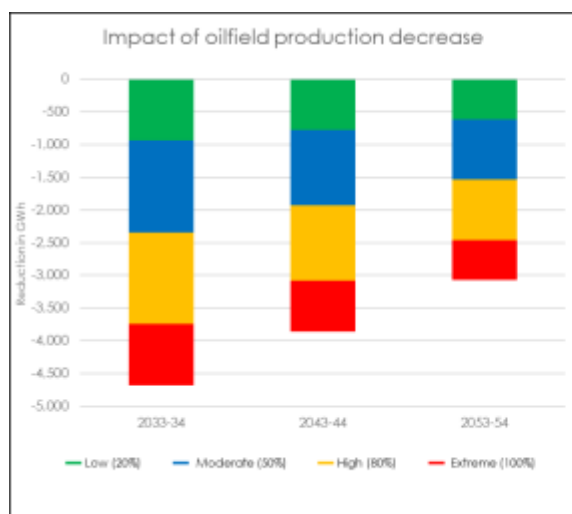
The oilfield forecast is sensitive to changes in the production forecast. The following tables show what the incremental oilfield energy and demand would be if actual fluid production is substantially different than the one derived from the

information provided by the Canadian Association of Petroleum Producers (CAPP), the National Energy Board (NEB), and the Ministry of Resources.

Production Higher than Forecast:



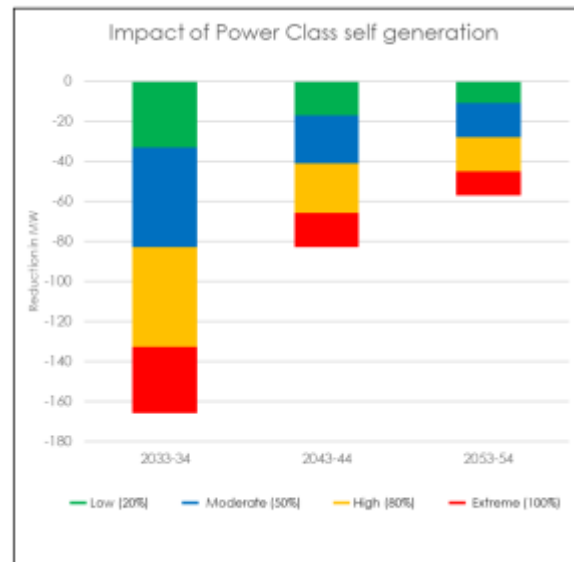
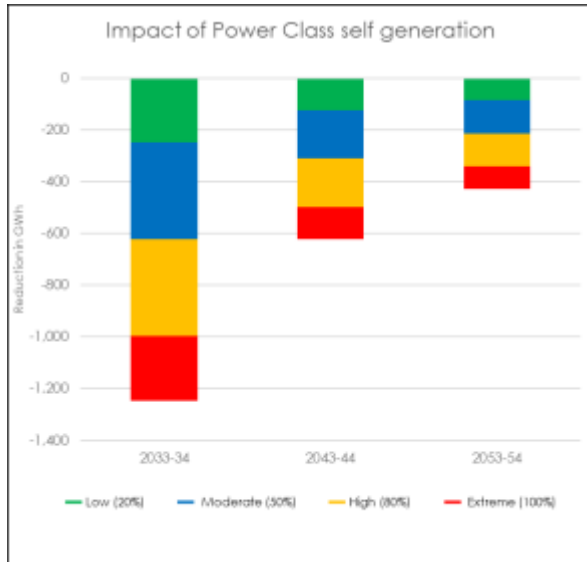
Production Lower than Forecast:



Power Class - Self Generation

Power class customers continue to express interest in self generating a portion (or all) of their load requirements to save on electrical costs (i.e., carbon tax) or meet their environmental goals. As stated previously, the potential for self generation has been incorporated into the Power class forecast by identifying known individual projects

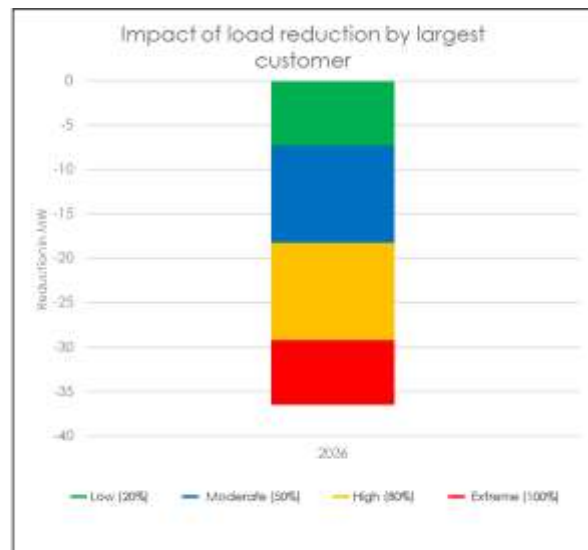
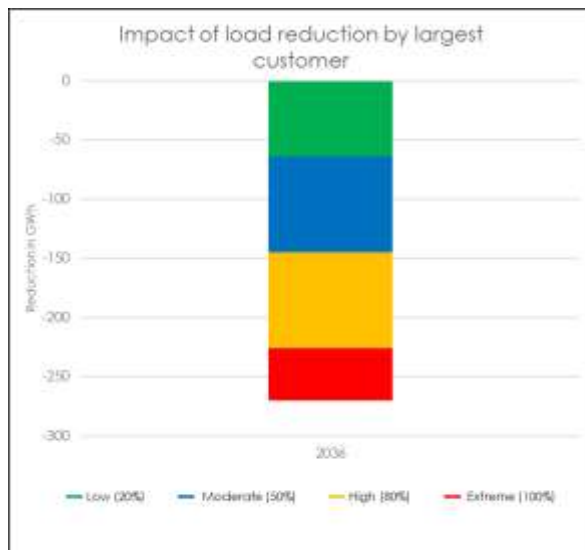
and assigning sizes in MVA and probabilities to them. The table below shows the amount of energy and demand reductions per year based on the prescribed percentage of power class energy fully defecting from the system due to self generation.



Power Class - Potential Expansions & Contractions

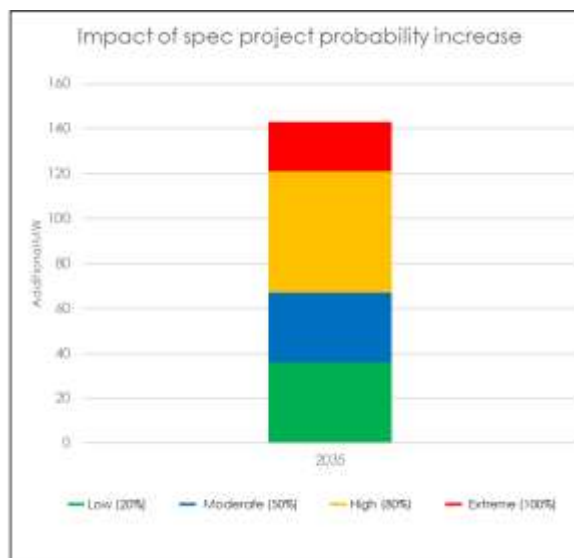
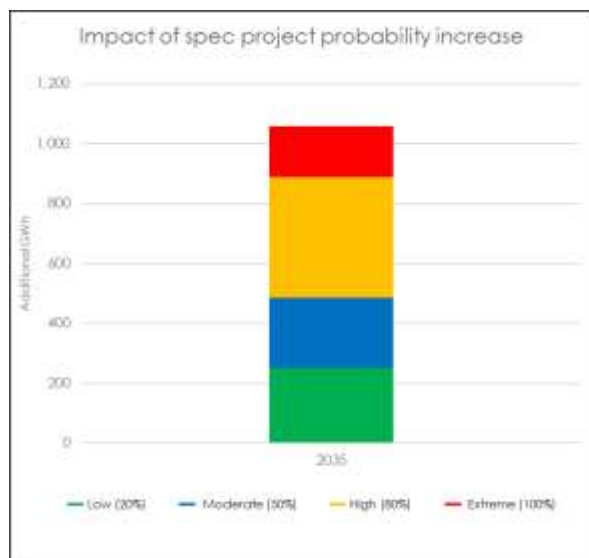
This scenario models the average annual impact to energy consumption and peak demand should

SaskPower's largest power customer reduce load by 20%, 50%, 80%, and 100% by 2034-35.



This scenario examines what the average annual impact to energy consumption and peak demand would be should 20%, 50%, 80%, and 100% of speculative projects proceed within the

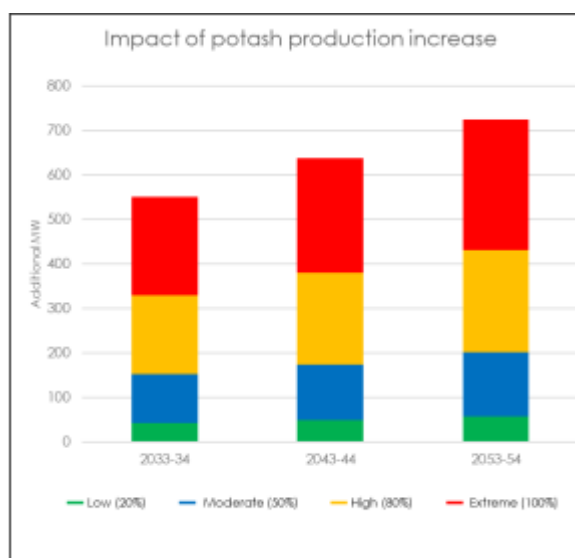
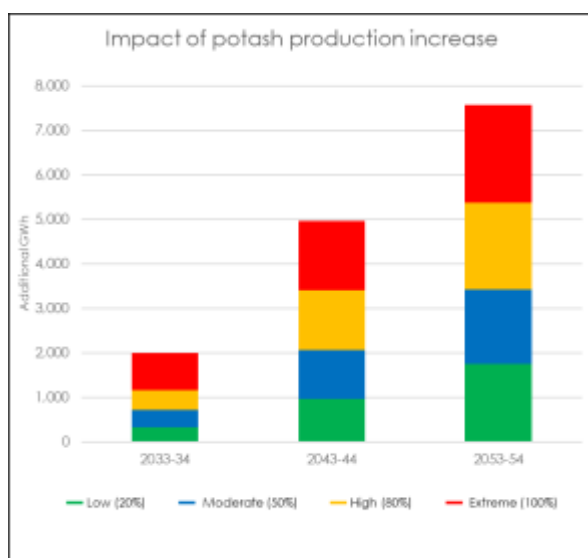
forecast period. The low, moderate, high, and extreme percentages represent the portion of total speculative load.



Potash - Production Forecast – Higher than Forecast

If actual production of potash in the province is higher than expected, SaskPower will sell more energy to potash sector customers. The table below shows the additional average annual energy and peak expected if production is 20%, 50%, 80%, and 100% higher than forecast in 2033-

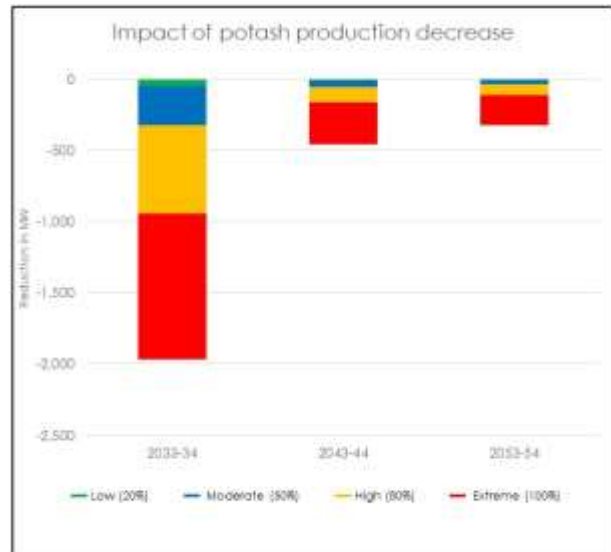
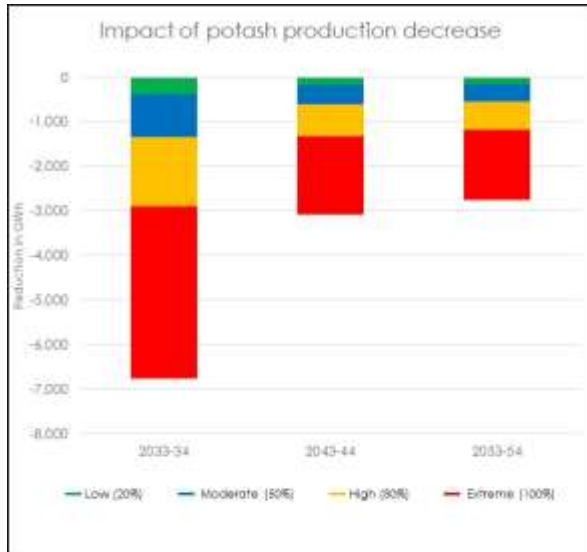
34, 2043-44, and 2053-54, respectively. Self-generation assumptions, load factors, and energy intensity were assumed to be constant in these scenarios. The increase in production was assumed to be constant through the target year.



Potash - Production Forecast – Lower Than Forecast

If actual production of potash in the province is lower than expected, SaskPower will sell less energy to potash sector customers. The table below shows the reduced average annual energy and peak expected if production is 20%, 50%, 80%, and 100% lower than forecast in 2033-34, 2043-44,

and 2053-54, respectively. Self-generation assumptions, load factors, and energy intensity were assumed to be constant in these scenarios. The decrease in production was assumed to be constant through the target year.



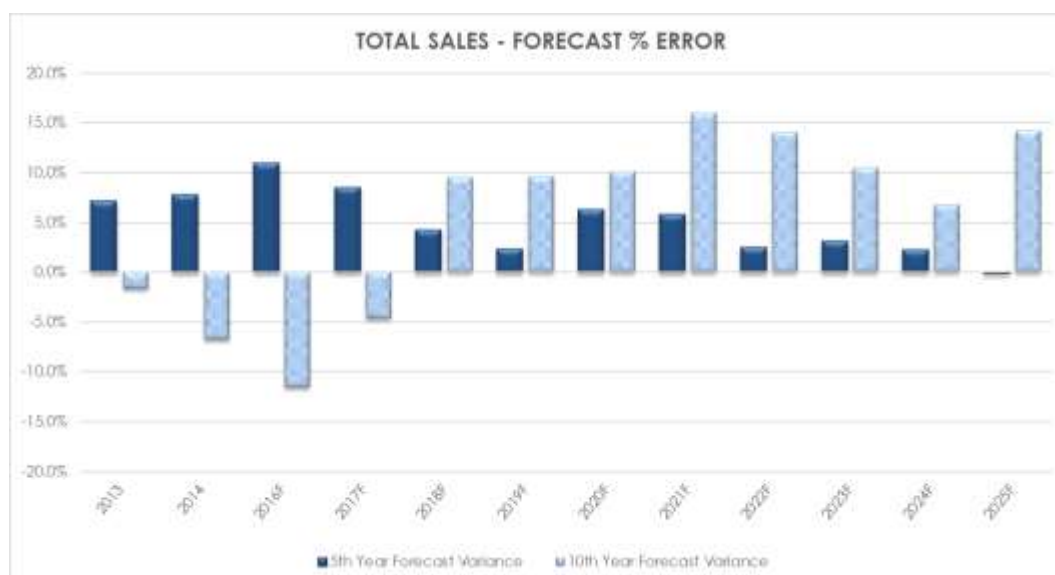
FORECAST ACCURACY – 5 AND 10 YEARS

OVERVIEW

The forecast assumes 15-year average weather patterns with expected economic and population growth. Although great care is taken to obtain as accurate a forecast as possible, some level of error is inevitable. Despite that uncertainty, it is still expected that the forecast will be within +/- 3% in the near term, +/- 5% in the five-year window, and +/- 10% in the 10-year window, however,

large swings in economic outcomes or customer behaviour can cause error percentages exceeding the targets. Recognizing this inherent uncertainty in the forecast, historic forecast variation has been tracked to actual results five and ten years later. The results are shown in the tables below.

TOTAL SALES FORECAST ACCURACY SUMMARY



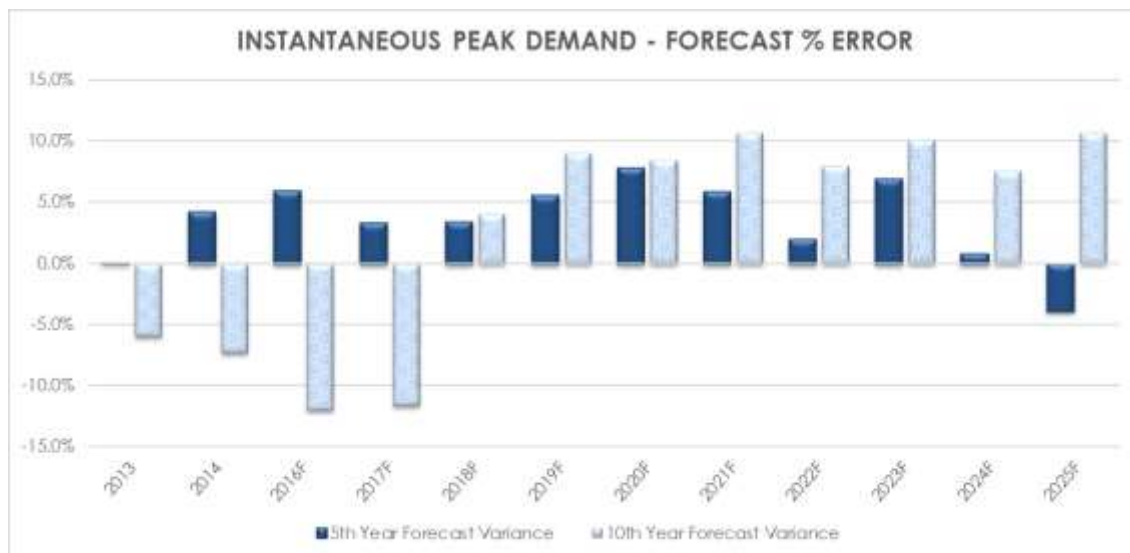
The total sales error analysis illustrates the percentage error of the forecast as compared to actuals in five- and ten-year increments. The table should be read as the comparison of the actual sales to the forecast that was created either five or ten years earlier. For example, the 2020-21 five-year comparison measures the 2015 forecast for 2020-21 while the ten-year comparison is to the 2010 forecast for 2020-21.

Year	5 YR Previous				10 YR Previous		
	Actuals Gwh	Forecast Gwh	Difference Gwh	Pct Error %	Forecast Gwh	Difference Gwh	Pct Error %
2013	20,852	22,444	1,592	7.1%	20,508	-344	-1.7%
2014	21,489	23,296	1,807	7.8%	20,129	-1,361	-6.8%
2016F	21,764	24,408	2,643	10.8%	19,512	-2,252	-11.5%
2017F	22,177	24,224	2,047	8.4%	21,203	-975	-4.6%
2018F	23,383	24,394	1,011	4.1%	25,833	2,451	9.5%
2019F	23,665	24,228	563	2.3%	26,181	2,516	9.6%
2020F	23,188	24,721	1,533	6.2%	25,788	2,600	10.1%
2021F	22,497	23,872	1,376	5.8%	26,775	4,279	16.0%
2022F	23,412	23,994	582	2.4%	27,215	3,802	14.0%
2023F	23,924	24,694	769	3.1%	26,730	2,805	10.5%
2024F	24,387	24,933	546	2.2%	26,160	1,773	6.8%
2025F	22,939	22,911	-28	-0.1%	26,736	3,797	14.2%

INSTANTANEOUS PEAK DEMAND FORECAST ACCURACY SUMMARY

Like the total sales error, the peak error analysis illustrates the percentage error of the forecast as compared to actuals in five- and ten-year increments. The table should be read as the comparison of the actual peak to the most likely

instantaneous forecast that was created either five or ten years earlier. For example, the 2020-21 five-year comparison is to the 2015 forecast for 2020-21 while the 2020-21 ten-year comparison is to the 2010 forecast for 2020-21.



Year	5 YR Previous				10 YR Previous		
	Actuals MW	Forecast MW	Difference MW	Pct Error %	Forecast MW	Difference MW	Pct Error %
2013	3,543	3,544	1	0.0%	3,343	-200	-6.0%
2014	3,561	3,717	156	4.2%	3,319	-242	-7.3%
2016F	3,640	3,870	230	5.9%	3,249	-391	-12.0%
2017F	3,747	3,875	128	3.3%	3,355	-392	-11.7%
2018F	3,792	3,925	133	3.4%	3,953	161	4.1%
2019F	3,723	3,942	219	5.5%	4,093	370	9.0%
2020F	3,722	4,036	314	7.8%	4,067	345	8.5%
2021F	3,722	3,953	231	5.8%	4,168	446	10.7%
2022F	3,910	3,990	80	2.0%	4,250	340	8.0%
2023F	3,800	4,083	283	6.9%	4,226	426	10.1%
2024F	3,896	3,927	31	0.8%	4,216	320	7.6%
2025F	3,838	3,694	-144	-3.9%	4,299	461	10.7%

GLOSSARY OF TERMS

Average Load of Appliances: the average annual energy used by an appliance in kWh.

Base Forecast: a forecast which does not assume any reductions in load from Demand Side Management incentives or programs.

Capacity (generation): “the rated output of a generator for a prescribed set of conditions which is typically the maximum power available continuously”⁴.

Solar Capacity Factor: the percentage output that is produced over a specific time⁴. Solar capacity factor combines multiple factors to be able to convert the solar nameplate kW to actual performance kW. This includes environmental factors such as the availability of the sun including clouds and nighttime, angle of the sun's rays on the system, and the duration of the day. Systems that track the sun can improve the capacity factor.

Coincident Load: a customer's (or class's) load at a specified hour.

Coincident Peak: a customer's (or class's) load at the hour of SaskPower's system peak.

Cooling Degree Days (CDD): a standardized measure of the number of degrees the average daily dry bulb temperature was warmer than a pre-determined cut-off point multiplied by the number of days where that occurred.

Customer: refers to a metered electrical service. A customer is not equivalent to one building structure. One building can have multiple electrical services and may count as more than one customer. Likewise, multiple customers may have only one service and therefore would count as only one customer. Streetlights group several installations, and each are defined as one customer.

Demand: The rate at which electric energy is delivered at a given instant or averaged over a specific time. It is measured in kilowatts, megawatts, etc.

Demand Side Management: is the modification of consumer demand for energy through various methods such as financial incentives, energy efficiency programs and behavioral change through education.

Dry Bulb Temperature: Temperature recorded in the absence of humidity and radiation with a device that is shielded from these elements.

Econometric Model: the use of economic data to help determine past and future economic trends using regression formulas.

Electric Vehicles (EV): any vehicle that uses some type of electric motor either on its own or in conjunction with an internal combustion engine (ICE).

Statistically adjusted End Uses: the types of electrical appliances used in a typical residential home.

Extrapolation: the action of estimating something by assuming that existing trends will continue.

GDP: Gross Domestic Product. The total known economy in dollars by a type of industry or a region (i.e., YGDP is Saskatchewan's GDP).

Gigawatt-hours (GWh): is a unit of energy representing one billion (1,000,000,000) watt hours and is equivalent to one million kilowatt hours.

⁴ <http://www.lifebynumbers.ca/the-solar-solution/solar-capacity-and-capacity-factor/>

Heating Degree Days (HDD): a standardized measure of the number of degrees the average daily dry bulb temperature was cooler than a pre-determined cut-off point multiplied by the number of days where that occurred.

Hi-Low Forecast: SaskPower's forecast that predicts a 90% probability that future energy and peak demand loads will fall within the range of the upper and lower boundaries.

Kilowatt-hours (kWh): a measure of electrical energy equivalent to a power consumption of 1,000 watts for 1 hour.

Load Factor: the ratio of a customer's average demand to their maximum (or coincident) demand in a specified period. Load factors can be calculated on a customer, class, or system basis.

Load Forecast Methodology: the process by which an energy and peak demand forecast for Saskatchewan is produced.

Market saturation and penetration rates: the percentage of total households that use a certain appliance.

Megawatt (MW): A unit of demand. One MW is a million watts. One thousand MW of demand for one hour equals one GWh of energy.

Most Likely Forecast: represents the total energy and demand levels placed on the supply system based on traditional (i.e., average) customer usage.

Oilfield Energy Intensity: kWh per cubic meter of oil or fluid (oil and water) production.

Peak load: the maximum load required during a given period. It is provided in terms of MW and reported as either instantaneous or interval.

Plug-In Electric Vehicles (PEVs): Vehicles that have an electric motor only.

Plug-In Hybrid Electric Vehicles (PHEVs): Vehicles that have both an electric motor and an ICE.

Potential System Peak Demand: represents the highest level of demand placed on the supply system at any time during the year if typical lighting loads occur and all large consumers are operating at their normal levels during below average weather conditions.

Power Factor: the ratio of the real power absorbed by the load to the apparent power flowing in the circuit. The difference between the two is caused by reactance in the circuit and represents power that does no useful work.

Regression analysis: a set of statistical processes for estimating the relationships between dependent and independent variables.

Speculative Load: longer term expansion plans or new projects which have not been approved or have a low probability of proceeding.

Station Service: the energy used by power plants to generate power and service their own loads.

System Peak Demand: highest amount of demand (usually measured in MW) used at a point in time through the fiscal year.

Use per Customer (UPC): unit of energy to represent the average use of a single customer over a specific period; usually expressed in kWh/customer/year.

Water production based on Water Cut: a ratio that describes the amount of oil extracted out of oil wells divided by the total fluid removed.

Weather Normalization: Process by which actual energy or peak outcomes are adjusted to would what have happened under normal weather conditions. SaskPower uses 30 years of weather data to normalize its load data.

APPENDICES

TABLE A1
2025-26 Q1 TOTAL SYSTEM LOAD FORECAST
ENERGY SALES AND NUMBER OF ACCOUNTS

Year	Power		Oilfields		Commercial		Residential		Farm		Reseller		Total Sales		Corporate Use		Exports	Losses	Total Energy Requirements
	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	GWh	GWh
2014	8,179.0	102	3,503.0	18,662	3,788.0	60,274	3,281.0	373,109	1,364.0	59,792	1,274.0	3	21,389.0	511,942	100.3	212	497.2	1,474.6	23,461.1
2015	8,698.0	121	3,494.0	19,307	3,795.0	61,231	3,128.0	380,392	1,276.0	59,262	1,234.0	3	21,625.0	520,316	101.2	212	89.9	1,520.6	23,336.6
2016-17	9,206.7	124	3,620.8	19,234	3,776.9	61,918	3,068.6	388,006	1,188.8	58,775	1,218.7	3	22,080.5	528,060	96.8	212	71.4	2,105.2	24,353.8
2017-18	9,844.8	124	3,877.5	19,412	3,861.9	62,375	3,162.2	392,314	1,327.8	58,492	1,208.4	3	23,282.7	532,720	100.5	212	175.7	1,861.7	25,420.5
2018-19	9,964.1	125	3,962.4	19,513	3,861.8	63,216	3,215.8	396,536	1,353.6	58,322	1,201.7	3	23,559.5	537,715	93.4	212	303.5	1,949.5	25,905.8
2019-20	9,583.7	130	4,163.6	19,466	3,748.1	63,757	3,091.1	399,394	1,329.8	57,978	1,155.9	3	23,072.2	540,728	116.0	212	253.7	1,541.3	24,983.2
2020-21	9,408.3	128	3,727.6	18,960	3,539.7	64,272	3,223.7	403,782	1,348.4	58,035	1,128.8	3	22,376.6	545,180	108.9	212	526.4	1,894.6	24,906.5
2021-22	9,820.7	127	4,012.9	19,103	3,690.3	64,764	3,330.9	407,995	1,284.9	57,949	1,160.5	3	23,300.1	549,941	109.4	212	695.2	1,707.8	25,812.5
2022-23	10,086.9	126	4,211.0	19,281	3,775.8	65,051	3,294.2	411,629	1,288.0	57,760	1,161.7	3	23,817.5	553,850	106.2	212	932.5	1,807.4	26,663.7
2023-24	10,530.5	134	4,319.9	19,318	3,749.1	65,303	3,223.8	415,037	1,305.4	57,649	1,150.1	3	24,278.7	557,444	108.3	212	763.0	1,256.8	26,406.8
2024-25	10,227.3	130	4,395.2	18,993	3,744.3	65,475	3,247.4	419,908	1,226.3	57,724	1,143.4	3	23,983.9	562,233	97.8	212	437.6	1,655.0	26,174.2
2025-26	10,968.2	111	4,452.8	18,928	3,750.1	65,744	3,252.9	422,075	1,289.8	58,788	1,140.0	3	24,853.8	565,648	95.0	213		1,723.2	26,672.0
2026-27	11,488.8	111	4,497.5	18,832	3,767.6	66,114	3,291.0	424,255	1,298.5	58,879	1,145.5	3	25,489.0	570,193	93.1	213		1,749.4	27,331.5
2027-28	11,961.2	111	4,565.5	18,771	3,785.7	66,484	3,347.5	430,494	1,306.8	58,866	1,148.7	3	26,115.4	574,728	89.7	213		1,735.4	27,940.5
2028-29	12,281.8	112	4,634.2	18,732	3,806.0	66,854	3,411.2	434,759	1,317.3	58,853	1,145.6	3	26,596.1	579,313	82.9	213		1,644.6	28,323.6
2029-30	12,321.6	112	4,678.9	18,707	3,826.0	67,224	3,481.4	439,068	1,324.7	58,840	1,145.6	3	26,778.2	583,954	71.3	213		1,657.8	28,507.3
2030-31	12,385.0	114	4,707.3	18,692	3,844.5	67,595	3,559.2	443,293	1,332.4	58,827	1,145.6	3	26,974.1	588,522	52.2	213		1,661.5	28,687.9
2031-32	12,412.9	114	4,737.4	18,681	3,865.3	67,965	3,653.6	447,229	1,340.0	58,814	1,148.7	3	27,157.9	592,806	52.7	213		1,651.8	28,862.4
2032-33	12,443.4	114	4,721.6	18,675	3,890.3	68,335	3,775.5	451,285	1,348.2	58,801	1,145.6	3	27,324.6	597,213	53.0	213		1,666.2	29,043.8
2033-34	12,474.7	114	4,681.9	18,671	3,919.5	68,705	3,935.0	455,445	1,356.9	58,788	1,145.6	3	27,513.6	601,726	53.4	213		1,672.2	29,239.1
2034-35	12,462.8	114	4,637.6	18,669	3,955.3	69,076	4,116.2	459,638	1,365.8	58,775	1,145.6	3	27,683.3	606,274	53.7	213		1,665.5	29,402.5
2035-36	12,472.5	114	4,590.2	18,667	3,990.9	69,446	4,267.8	463,810	1,374.3	58,762	1,148.7	3	27,844.4	610,801	54.2	213		1,686.3	29,584.9
Growth Rates (%)																			
2022F to 2023F	-2.9%	-3.0%	1.7%	-1.7%	-0.1%	0.3%	0.7%	1.2%	-6.1%	0.1%	-0.6%	0.0%	-1.2%	0.9%	-9.7%	0.0%	-42.6%	31.7%	-0.9%
2023F to 2024F	7.2%	-14.6%	1.3%	-0.3%	0.2%	0.4%	0.2%	0.5%	5.2%	1.8%	-0.3%	0.0%	3.6%	0.6%	-2.8%	0.5%		4.1%	1.9%
5 YR Historic	1.3%	0.0%	1.1%	-0.5%	0.0%	0.5%	1.0%	1.0%	-1.6%	-0.1%	-0.2%	0.0%	0.8%	0.8%	-3.4%	0.0%	11.5%	1.4%	0.9%
10 YR Historic	2.3%	2.5%	2.3%	0.2%	-0.1%	0.8%	-0.1%	1.2%	-1.1%	-0.4%	-1.1%	0.0%	1.2%	0.9%	-0.3%	0.0%	-1.3%	1.2%	1.1%
5 YR Forecast	2.5%	0.5%	1.1%	-0.3%	0.5%	0.6%	1.8%	1.0%	0.7%	0.0%	0.1%	0.0%	1.7%	0.8%	-11.3%	0.0%		-0.7%	1.5%
10 YR Forecast	1.3%	0.3%	0.3%	-0.1%	0.6%	0.5%	2.8%	0.9%	0.6%	0.0%	0.1%	0.0%	1.1%	0.8%	-5.5%	0.0%		-0.2%	1.0%

Notes:

- 1.) All forecasted energy values are normalized to reflect 15-year average weather patterns. Actuals reflect billed sales (non-normalized).
2.) The forecast number of accounts is the average for the year as required for rate design and revenue forecasting.
3.) The forecast Total Energy Requirements forecast does not include exports as they are considered non-firm; however, actual energy DOES include exports

TABLE A2
2025-26 Q1 GRID ONLY LOAD FORECAST
ENERGY SALES AND NUMBER OF ACCOUNTS

Year	Power		Oilfields		Commercial		Residential		Farm		Reseller		Total Sales		Corporate Use		Exports		Losses		Total Energy Requirements	
	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts
2014	8,179.0	102	3,503.0	18,662	3,779.7	60,082	3,259.7	371,950	1,364.0	59,792	1,274.0	3	21,359.4	510,591	100.0	210	497.2	1,473.0	1,473.0	23,429.6		
2015	8,698.0	121	3,494.0	19,307	3,787.3	61,035	3,108.9	379,227	1,276.0	59,262	1,234.0	3	21,598.2	518,955	100.8	210	89.9	1,519.0	1,519.0	23,307.9		
2016-17	9,206.7	124	3,620.8	19,234	3,769.1	61,757	3,050.3	386,928	1,188.8	58,775	1,218.7	3	22,054.5	526,821	96.4	210	71.4	2,102.6	2,102.6	24,324.8		
2017-18	9,844.8	124	3,877.5	19,412	3,854.1	62,182	3,142.8	391,234	1,327.8	58,492	1,208.4	3	23,255.5	531,447	100.1	210	175.7	1,859.8	1,859.8	25,391.1		
2018-19	9,964.1	125	3,962.4	19,513	3,854.0	63,023	3,196.5	395,461	1,353.6	58,322	1,201.7	3	23,532.3	536,447	93.0	210	303.5	1,947.5	1,947.5	25,876.4		
2019-20	9,583.7	130	4,163.6	19,466	3,740.8	63,565	3,091.1	398,319	1,329.8	57,978	1,155.9	3	23,065.0	539,461	115.6	210	253.7	1,519.4	1,519.4	24,953.7		
2020-21	9,408.3	128	3,727.6	18,960	3,532.3	64,076	3,223.7	402,715	1,348.4	58,035	1,128.8	3	22,369.2	543,917	108.5	210	526.4	1,872.9	1,872.9	24,877.0		
2021-22	9,820.7	127	4,012.9	19,103	3,683.6	64,584	3,313.8	406,934	1,284.9	57,949	1,160.5	3	23,276.4	548,700	109.3	210	695.2	1,704.5	1,704.5	25,785.4		
2022-23	10,086.9	126	4,211.0	19,281	3,768.5	64,873	3,274.6	410,566	1,288.0	57,760	1,161.7	3	23,790.6	552,609	106.1	210	932.5	1,806.0	1,806.0	26,635.2		
2023-24	10,530.5	134	4,319.9	19,318	3,741.7	65,125	3,204.2	413,974	1,305.4	57,649	1,150.1	3	24,251.7	556,203	108.2	210	763.0	1,255.4	1,255.4	26,378.3		
2024-25	10,227.3	130	4,395.2	18,993	3,736.9	65,297	3,227.8	418,845	1,226.3	57,724	1,143.4	3	23,956.9	560,992	97.6	210	437.6	1,653.6	1,653.6	26,145.8		
2025-26	10,968.2	111	4,452.8	18,928	3,743.1	65,564	3,234.8	421,031	1,289.8	58,788	1,140.0	3	24,828.7	564,424	94.9	211		1,720.0	1,720.0	26,643.6		
2026-27	11,488.8	111	4,497.5	18,832	3,760.6	65,934	3,273.0	425,211	1,298.5	58,879	1,145.5	3	25,463.9	568,969	92.9	211		1,746.2	1,746.2	27,303.0		
2027-28	11,961.2	111	4,565.5	18,771	3,778.7	66,304	3,329.4	429,434	1,306.8	58,866	1,148.7	3	26,090.3	573,488	89.5	211		1,732.1	1,732.1	27,912.0		
2028-29	12,281.8	112	4,634.2	18,732	3,798.9	66,674	3,393.2	433,699	1,317.3	58,853	1,145.6	3	26,571.0	578,073	82.7	211		1,641.4	1,641.4	28,295.2		
2029-30	12,321.6	112	4,678.9	18,707	3,819.0	67,044	3,463.3	438,008	1,324.7	58,840	1,145.6	3	26,753.0	582,714	71.2	211		1,654.6	1,654.6	28,478.8		
2030-31	12,385.0	114	4,707.3	18,692	3,837.4	67,415	3,541.1	442,233	1,332.4	58,827	1,145.6	3	26,949.0	587,282	52.1	211		1,658.3	1,658.3	28,659.4		
2031-32	12,412.9	114	4,737.4	18,681	3,858.2	67,785	3,635.6	446,169	1,340.0	58,814	1,148.7	3	27,132.8	591,566	52.5	211		1,648.6	1,648.6	28,834.0		
2032-33	12,443.4	114	4,721.6	18,675	3,883.3	68,155	3,757.4	450,225	1,348.2	58,801	1,145.6	3	27,299.5	595,973	52.9	211		1,663.0	1,663.0	29,015.4		
2033-34	12,474.7	114	4,681.9	18,671	3,912.4	68,525	3,917.0	454,385	1,356.9	58,788	1,145.6	3	27,488.5	600,486	53.2	211		1,668.9	1,668.9	29,210.7		
2034-35	12,462.8	114	4,637.6	18,669	3,948.3	68,896	4,098.1	458,578	1,365.8	58,775	1,145.6	3	27,658.1	605,034	53.6	211		1,662.3	1,662.3	29,374.1		
2035-36	12,472.5	114	4,590.2	18,667	3,983.8	69,266	4,249.7	462,750	1,374.3	58,762	1,148.7	3	27,819.3	609,561	54.0	211		1,683.1	1,683.1	29,556.5		

Growth Rates (%)

2022F to 2023F	-2.9%	-3.0%	1.7%	-1.7%	-0.1%	0.3%	0.7%	1.2%	-6.1%	0.1%	-0.6%	0.0%	-1.2%	0.9%	-9.7%	0.0%	-42.6%	31.7%	-0.9%	
2023F to 2024F	7.2%	-14.6%	1.3%	-0.3%	0.2%	0.4%	0.2%	0.5%	5.2%	1.8%	-0.3%	0.0%	3.6%	0.6%	-2.8%	0.5%		4.0%	1.9%	
5 YR Historic	1.3%	0.0%	1.1%	-0.5%	0.0%	0.5%	0.9%	1.0%	-1.6%	-0.1%	-0.2%	0.0%	0.8%	0.8%	-3.3%	0.0%	11.5%	1.7%	0.9%	
10 YR Historic	2.3%	2.5%	2.3%	0.2%	-0.1%	0.8%	-0.1%	1.2%	-1.1%	-0.4%	-1.1%	0.0%	1.2%	0.9%	-0.2%	0.0%	-1.3%	1.2%	1.1%	
5 YR Forecast	2.5%	0.5%	1.1%	-0.3%	0.5%	0.6%	1.8%	1.0%	0.7%	0.0%	0.1%	0.0%	1.7%	0.8%	-11.3%	0.0%		-0.7%	1.5%	
10 YR Forecast	1.3%	0.3%	0.3%	-0.1%	0.6%	0.6%	2.8%	0.9%	0.6%	0.0%	0.1%	0.0%	1.1%	0.8%	-5.5%	0.0%		-0.2%	1.0%	

Notes:

- 1.) All forecasted energy values are normalized to reflect 15-year average weather patterns. Actuals reflect billed sales (non-normalized).
- 2.) The forecast number of accounts is the average for the year as required for rate design and revenue forecasting.
- 3.) The forecast Total Energy Requirements forecast does not include exports as they are considered non-firm, however, actual energy DQES include exports

TABLE A3
2026 Q1 NON-GRID LOAD FORECAST
ENERGY SALES AND NUMBER OF ACCOUNTS

Year	Commercial		Residential		Total Sales		Corporate Use		Losses	Total Energy Requirements	
	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts	GWh	# of Accts		GWh	GWh
2014	8.3	192	21.3	1,159	29.6	1,351	0.3	2	1.6	31.5	31.5
2015	7.7	196	19.1	1,165	26.8	1,361	0.4	2	1.5	28.7	28.7
2016-17	7.8	161	18.3	1,078	26.0	1,239	0.3	2	2.6	29.0	29.0
2017-18	7.8	193	19.4	1,080	27.2	1,273	0.4	2	1.9	29.5	29.5
2018-19	7.8	193	19.4	1,075	27.2	1,268	0.4	2	1.9	29.5	29.5
2019-20	7.2	192	0.0	1,075	7.2	1,267	0.4	2	21.9	29.5	29.5
2020-21	7.4	196	0.0	1,067	7.4	1,263	0.4	2	21.7	29.5	29.5
2021-22	6.7	180	17.0	1,062	23.7	1,242	0.1	2	3.2	27.1	27.1
2022-23	7.3	178	19.6	1,063	26.9	1,241	0.1	2	1.4	28.5	28.5
2023-24	7.4	178	19.6	1,063	27.0	1,241	0.1	2	1.4	28.5	28.5
2024-25	7.3	178	19.6	1,063	26.9	1,241	0.1	2	1.4	28.5	28.5
2025-26	7.1	180	18.1	1,044	25.1	1,224	0.1	2	3.2	28.5	28.5
2026-27	7.1	180	18.1	1,044	25.1	1,224	0.1	2	3.2	28.5	28.5
2027-28	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2028-29	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2029-30	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2030-31	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2031-32	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2032-33	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2033-34	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2034-35	7.1	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
2035-36	7.0	180	18.1	1,060	25.1	1,240	0.1	2	3.2	28.5	28.5
Growth Rates (%)											
2022F to 2023F	-0.5%	0.0%	0.0%	0.0%	-0.1%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%
2023F to 2024F	-3.8%	1.1%	-7.9%	-1.8%	-6.8%	-1.3%	12.3%	0.0%	128.5%	0.0%	0.0%
5 YR Historic	0.3%	-1.5%	#NUM!	-0.2%	30.2%	-0.4%	-21.8%	0.0%	-42.2%	-0.7%	-0.7%
10 YR Historic	-1.2%	-0.8%	-0.8%	-0.9%	-0.9%	-0.8%	-8.6%	0.0%	-1.4%	-1.0%	-1.0%
5 YR Forecast	0.0%	0.0%	0.0%	0.3%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
10 YR Forecast	0.0%	0.0%	0.0%	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%

Notes:

1) Losses are calculated by taking the difference between Total Energy Requirements and Total Sales. The Total Sales and Total Energy Requirements are forecasted.

TABLE A4
2026 Q1 LOAD FORECAST
INSTANTANEOUS SYSTEM PEAK DEMAND FORECAST

Year	HISTORICAL		MOST LIKELY		POTENTIAL	
	Winter MW	Summer MW	Winter MW	Summer MW	Winter MW	Summer MW
2014	3,543	3,187				
2015	3,561	3,161				
2016-17	3,747	3,317				
2017-18	3,792	3,470				
2018-19	3,723	3,524				
2019-20	3,722	3,437				
2020-21	3,722	3,481				
2021-22	3,910	3,547				
2022-23	3,800	3,597				
2023-24	3,896	3,669				
2024-25	3,838	3,669				
2025-26			4,018	3,716	4,103	3,797
2026-27			4,115	3,799	4,203	3,879
2027-28			4,189	3,891	4,279	3,973
2028-29			4,226	3,960	4,316	4,046
2029-30			4,258	3,996	4,348	4,081
2030-31			4,287	4,026	4,378	4,111
2031-32			4,313	4,050	4,404	4,135
2032-33			4,358	4,074	4,450	4,160
2033-34			4,395	4,121	4,488	4,207
2034-35			4,428	4,155	4,522	4,243
2035-36			4,459	4,187	4,553	4,275

Growth Rates (%)

2022F to 2023F	-1.5%	0.0%				
2023F to 2024F			4.7%	1.3%	6.9%	3.5%
5 YR Historic	0.6%	1.3%				
10 YR Historic	0.8%	1.4%				
5 YR Forecast			1.3%	1.6%	1.3%	1.6%
10 YR Forecast			1.0%	1.2%	1.0%	1.2%

Notes:

- 1.) The Most Likely Peaks are based on the actual weather experienced at the time of the system peaks over the last 5 years
- 2.) The Potential Winter peak is based on sustained cold weather occurring in the first 3 weeks of December
- 3.) The Potential Summer peak is based on sustained hot weather occurring in July

TABLE A5
2026 Q1 TOTAL SYSTEM LOAD FORECAST
ENERGY SALES BY CUSTOMER SECTOR

GRID & NON-GRID (GWH)	2026F	2027F	2028F	2029F	2030F	2031F	2032F	2033F	2034F	2035F	2036F	10 year Growth
	Residential	3,291.0	3,347.5	3,411.2	3,481.4	3,559.2	3,653.6	3,775.5	3,935.0	4,116.2	4,267.8	2.8%
Farm & Industrial Irrigation												
	1,289.8	1,298.5	1,306.8	1,317.3	1,324.7	1,332.4	1,340.0	1,348.2	1,356.9	1,365.8	1,374.3	0.6%
Standard Oilfield												
Large Oilfield	3,660.1	3,704.8	3,770.6	3,841.5	3,886.2	3,914.6	3,942.5	3,928.9	3,889.2	3,844.9	3,795.4	0.4%
Total Oilfield	792.7	792.7	794.9	792.7	792.7	792.7	794.9	792.7	792.7	792.7	794.9	0.0%
	4,452.8	4,497.5	4,565.5	4,634.2	4,678.9	4,707.3	4,737.4	4,721.6	4,681.9	4,637.6	4,590.2	0.3%
Commercial												
Streelights	3,722.5	3,739.8	3,757.7	3,777.7	3,797.7	3,816.0	3,836.6	3,861.4	3,890.5	3,926.2	3,961.5	0.6%
	27.6	27.8	28.0	28.2	28.3	28.5	28.7	28.9	29.0	29.1	29.4	0.6%
Total Commercial	3,750.1	3,767.6	3,785.7	3,806.0	3,826.0	3,844.5	3,865.3	3,890.3	3,919.5	3,955.3	3,990.9	0.5%
Potash												
Pipeline Pumping	2,942.5	3,073.6	3,429.3	3,735.7	3,783.0	3,783.3	3,784.4	3,781.8	3,777.2	3,777.5	3,778.6	2.5%
Pulp & Paper	3,715.4	3,709.1	3,705.7	3,682.9	3,605.6	3,604.2	3,603.2	3,601.5	3,599.9	3,598.6	3,597.5	-0.3%
Steel	752.4	752.4	754.5	752.4	752.4	752.4	754.5	752.4	752.4	752.4	754.5	0.0%
Chemical Processing	667.8	667.7	669.5	667.7	667.7	667.7	669.5	667.7	667.7	667.7	669.5	0.0%
Oil	400.9	400.9	402.0	400.9	400.9	400.9	402.0	400.9	400.9	400.9	402.0	0.0%
	33.1	33.1	33.2	33.1	33.1	33.1	33.2	33.1	33.1	33.1	33.2	0.0%
Refineries	837.0	945.3	947.8	945.3	953.8	974.3	977.0	974.3	974.3	974.3	977.0	1.6%
Coal Mines	76.3	76.3	76.5	76.3	76.3	76.3	76.5	76.3	76.3	76.3	76.5	0.0%
Northern Mines	429.0	468.9	493.1	484.1	497.6	502.5	497.4	501.8	494.6	486.6	488.1	1.3%
Universities	227.6	227.6	228.2	227.6	227.6	227.6	228.2	227.6	227.6	227.6	228.2	0.0%
Other Key Accounts	808.8	829.5	830.0	823.9	824.4	825.5	827.8	825.5	825.5	825.5	831.7	0.3%
Misc Spec & DSM	77.4	304.4	391.3	452.0	499.3	537.2	559.3	600.5	645.1	642.3	635.5	0.0%
Total Power Accounts	10,968.2	11,488.8	11,961.2	12,281.8	12,321.6	12,385.0	12,412.9	12,443.4	12,474.7	12,462.8	12,472.5	1.3%
Saskatoon												
Swift Current	1,001.4	1,006.7	1,009.5	1,006.7	1,006.7	1,006.7	1,009.5	1,006.7	1,006.7	1,006.7	1,009.5	0.1%
Resellers	138.7	138.8	139.3	138.9	138.9	138.9	139.3	138.9	138.9	138.9	139.3	0.0%
	1,140.0	1,145.5	1,148.7	1,145.6	1,145.6	1,145.6	1,148.7	1,145.6	1,145.6	1,145.6	1,148.7	0.1%
Corporate Use												
	95.0	93.1	89.7	82.9	71.3	52.2	52.7	53.0	53.4	53.7	54.2	-5.5%
Total Grid Sales												
	24,948.9	25,582.1	26,205.1	26,679.0	26,849.5	27,026.3	27,210.6	27,377.6	27,567.0	27,737.0	27,898.6	1.1%
Losses & Unaccounted												
	1,723.0	1,749.4	1,735.4	1,644.6	1,657.8	1,661.5	1,651.8	1,666.2	1,672.2	1,665.5	1,686.3	-0.2%
Total Energy Requirements												
	26,671.9	27,331.5	27,940.5	28,323.6	28,507.3	28,687.9	28,862.4	29,043.8	29,239.1	29,402.5	29,584.9	1.0%

Notes:
1.) All forecasted energy values are normalized to reflect 30-year average weather patterns.

TABLE A6
EXTREME EVENT DETAILS

Electric Heat - Residential	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	469	70	1,174	176	1,878	281	2,347	352
2043-44	523	78	1,307	196	2,091	313	2,614	392
2053-54	541	81	1,352	202	2,163	324	2,704	405

Electric Heat - Farm	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	59	9	147	22	236	35	295	44
2043-44	64	10	160	24	256	38	320	48
2053-54	66	10	164	25	262	39	328	49

Electric Heat - Commercial	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	115	17	288	43	460	69	575	86
2043-44	171	26	426	64	682	102	853	128
2053-54	255	38	638	95	1,021	153	1,276	191

Electric Vehicles Residential	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	259	93	648	232	1,037	371	1,296	464
2043-44	172	57	429	142	686	227	858	284
2053-54	52	17	130	42	209	67	261	84

Electric Vehicles Commercial	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	49	18	122	44	196	70	245	88
2043-44	80	27	201	67	322	107	402	133
2053-54	101	33	251	81	402	130	503	162

Electric Vehicles Farm	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	37	13	93	33	148	53	185	66
2043-44	42	14	104	35	167	55	209	69
2053-54	43	14	108	35	173	56	216	70

Net Metering:

Residential - 8 kVa	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(186)	(41)	(465)	(102)	(744)	(163)	(929)	(204)
2043-44	(203)	(44)	(507)	(111)	(811)	(177)	(1,013)	(221)
2053-54	(205)	(45)	(512)	(112)	(819)	(180)	(1,024)	(225)

Commercial - 63 kVa	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(220)	(48)	(551)	(121)	(881)	(193)	(1,102)	(242)
2043-44	(247)	(54)	(616)	(135)	(986)	(215)	(1,232)	(269)
2053-54	(260)	(57)	(650)	(143)	(1,040)	(228)	(1,300)	(285)

Oilfield - 221 kVa	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(213)	(47)	(531)	(117)	(850)	(187)	(1,062)	(233)
2043-44	(227)	(50)	(568)	(124)	(909)	(199)	(1,136)	(248)
2053-54	(229)	(50)	(574)	(126)	(918)	(201)	(1,147)	(252)

Farm - 19 kVa	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(60)	(13)	(150)	(33)	(241)	(53)	(301)	(66)
2043-44	(63)	(14)	(159)	(35)	(254)	(55)	(317)	(69)
2053-54	(63)	(14)	(158)	(35)	(253)	(55)	(316)	(69)

Oil Production Higher than Forecast:

Production Forecast	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	1,405	186	2,341	310	3,746	496	4,682	619
2043-44	1,157	153	1,929	255	3,086	408	3,857	510
2053-54	922	122	1,537	203	2,460	325	3,075	407

Oil Production Lower than Forecast:

Production Forecast	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(936)	(124)	(2,341)	(310)	(3,746)	(496)	(4,682)	(619)
2043-44	(771)	(102)	(1,929)	(255)	(3,086)	(408)	(3,857)	(510)
2053-54	(615)	(81)	(1,537)	(203)	(2,460)	(325)	(3,075)	(407)

Self-Generation	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(249)	(33)	(623)	(83)	(997)	(133)	(1,246)	(166)
2043-44	(124)	(17)	(310)	(41)	(497)	(66)	(621)	(83)
2053-54	(85)	(11)	(214)	(28)	(342)	(45)	(427)	(57)

Scenario	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
Largest single customer reduces load by 2035	(547)	(76)	(1,367)	(191)	(2,187)	(306)	(2,733)	(382)

Scenario	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
All Spec projects set to 100% probability	250	36	235	31	404	54	169	22

Potash Production Higher than Forecast:

Production Forecast	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	334	43	388	109	441	177	836	221
2043-44	970	50	1,103	124	1,338	205	1,551	257
2053-54	1,756	58	1,672	144	1,939	228	2,206	294

Potash Production Lower than Forecast:

Production Forecast	Low (20%)		Moderate (50%)		High (80%)		Extreme (100%)	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2033-34	(387)	(50)	(968)	(273)	(1,549)	(620)	(3,873)	(1,023)
2043-44	(177)	(9)	(442)	(50)	(707)	(109)	(1,768)	(293)
2053-54	(158)	(5)	(394)	(34)	(631)	(74)	(1,577)	(210)

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Section 8: Latest actual and current prospective Cost of Service and Allocation Study Reports together with the latest external Cost of Service Study and methodologies in use

2024 FISCAL BASE EMBEDDED COST OF SERVICE STUDY

PREPARED BY:

Pricing & Costing

of

Pricing & Energy Forecasting

Submitted On:

December 22, 2025

❖ *BASED ON 2023-24 FISCAL AUDITED FINANCIAL STATEMENTS AND SCHEDULES*

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I. INTRODUCTION

A. Purpose

The SaskPower 2024 Fiscal (2024F) Base Cost of Service Study provides an in-depth, detailed account of the annual cost to serve each of SaskPower's customer classes at the end of the fiscal year (ending March 31, 2024). The primary purpose is to provide an indication of the extent by which revenues contributed from a particular class, recover the allocated costs of serving that customer class.

To remain viable, SaskPower must be given the opportunity to recover its incurred costs of providing electric service to its various classes of customers. Cost of service is usually defined to include all a utility's operating expenses, plus a reasonable return on its investment ("rate base") devoted to the service of the rate paying public. These stakeholders and their interests are as follows:

1. **Saskatchewan Rate Review Panel (SRRP):** The Saskatchewan Rate Review Panel is interested in assuring that SaskPower only includes costs and returns that are related to SaskPower's core business. They are also interested in assuring that SaskPower applies methodologies that are reasonable and acceptable. The SRRP also relies on the opinion of an external consultant to report on the reasonableness of the embedded Cost of Service Study.
2. **SaskPower Management / Executive / Board:** SaskPower's Executive, Management, and Board are interested in ensuring that the corporation's financial targets are achieved. The cost of service model is vital to the development of rates and achieving SaskPower's revenue requirement.
3. **Customers:** The cost of service provides documentation to these stakeholders in terms of how much of the cost to provide them with service is recovered through the rates they pay.

B. Scope

A Cost of Service Study is a study of the costs incurred by SaskPower in producing, transmitting, and distributing electricity to its customers, by customer class, in relation to revenues collected from each class under existing rates. For this report the costs analyzed are the actual historical "embedded" costs of the existing plant and expenses in the fiscal "Base year" of 2024.

NorthPoint Energy Solutions is a SaskPower owned subsidiary company. The financial assets and expenses from this subsidiary have been included in this year's Cost of Service Study.

Best practices from other utilities across Canada have shown it is prudent to rate payers for a utility to include subsidiary financial results in years when the subsidiary achieves a net gain. In years of net loss, subsidiaries will not be included in the Cost of Service Study.

C. Objectives

Cost of service studies are among the basic tools of rate-making. While non-cost concepts and principles can modify the cost-based standard, cost of service methodology remains the primary factor in determining the reasonableness of rates. SaskPower's key objectives of the Cost of Service Study and resulting rate design are as follows:

1. Meeting Revenue Requirement
2. Fairness and Equity
3. Economic Efficiency
4. Conservation of Resources
5. Simplicity and Administrative Ease
6. Stability and Gradualism

Meeting Revenue Requirement

Meeting the revenue requirement suggests that SaskPower's customer rates are designed with the purpose to provide sufficient revenue to cover both the utility's forecasted annual costs and return on rate base. Annual costs and the return on rate base are further explained within Step 1 of the Identification section of the cost of service methodology.

Fairness and Equity

Fairness and equity implies that SaskPower's cost of service methodology and rate design is applied to the various customer classes, based on cost behaviour drivers and cost causality, while projecting no undue discrimination between customers.

Economic Efficiency

Economic efficiency refers to SaskPower's objective of utilizing assets and expenses in a manner that is operationally effective for developing a power system, while the rates charged for electrical service provide the appropriate price signals to customers that will allow SaskPower to maintain a power system that continues to be efficient over time.

Conservation of Resources

Conservation of resources relies on asset and cost allocations that provide appropriate price signals to consumers, so that they will utilize power in a reasonable manner while considering SaskPower's cost of providing power and the value placed on that power by the various customer classes.

Simplicity and Administrative Ease

Simplicity and administrative ease objectives for rate-making rely on concepts of allocation that are logical, transparent to stakeholders and customers, and easily implementable.

Stability and Gradualism

Stability and gradualism objectives aspire to employ cost allocations and rate-making standards that are steady over longer periods. Stability and gradualism goals avoid non-typical volatility of rates to any customer classes at any given time.

Since the above objectives do not always agree with the concept that service should be provided on a cost basis, SaskPower must use judgement and the advice of our shareholder and Cabinet as to the appropriate courses of action.

D. Cost of Service Methodology Changes

The latest review of SaskPower's cost of service and rate design methodology occurred in 2023 (January - June). The review was conducted by Elenchus Research Associates, from Toronto, Ontario.

Elenchus filed its final report on June 30, 2023 which stated, in their view, SaskPower's current cost allocation methodology is consistent with accepted rate making principles and practices, is consistent with methodologies commonly used by other electric utilities, and is reflective of SaskPower's operational circumstances, with some recommendations for enhancements:

1) Removal of the coincident peak allocation methodology (Bary correction) in rate design.

SaskPower previously employed an adjustment when designing rates for classes of customers where customers load factors and coincidence factors varied. Within these classes of customers, high load factor customers typically have higher coincidence factors, meaning they consume more electricity consistently, and particularly at system peak, resulting in more capacity costs.

The Bary correction's main purpose was to shift some of the demand-related costs to be recovered through the energy charge. This adjustment was also beneficial in being more equitable with cost causality, where customers were being billed for costs that they were responsible for causing.

The unintended effect was a distorted price signal for energy and demand charges, where inflated energy charges and lower demand charges provided an incorrect price

signal for customers to defect from the grid and/or self-generate, to avoid the higher energy charges. These signals gave an inadvertent effect of shifting demand costs from self-generation customers to other SaskPower customers who did not create the burden of these costs.

Starting in 2022, SaskPower gradually began phasing out the Bary correction within its rate design and Elenchus supports this change.

2) Further investigate the deployment of Time of Use (TOU) rates as a means to managing the demand with the intention of minimizing the need for new capacity.

TOU rates have been implemented by various utilities in a response to providing an accurate price signal to customers for consuming electricity at varying times of a day, and/or season with the intention of reducing generation costs which cascade to lower utility costs and ultimately, lower bills for customers. The purpose of TOU rates is to influence customers to change their electricity consumption behaviours from high-cost periods to low-cost periods, which allows a power utility to reduce its total costs during peak periods or during periods of higher expense incurred periods.

In order for TOU rates to be utilized, more Advanced Metering Infrastructure (AMI) needs to be deployed including proper metering, and billing systems, along with appropriate economic differentials in marginal cost that utilities can present to entice customers to shift their demand and reduce a utility's average cost of power.

With SaskPower's inherent system load factor of 75% at this current time, and projected new load relatively being flat, there is minimal opportunity for SaskPower to shift load. Elenchus recommended a continuation with current rate structure, but if conditions change and marginal costs increase, SaskPower should consider a move to TOU rates.

3) Rate Alignment options

SaskPower employs a typical rate structure for all classes that aligns rate components (e.g. fixed charges, demand charges and energy charges) with their corresponding classified costs (customer-related, demand-related and energy-related) where it is feasible, based on metering technology availability, while avoiding unintended consequences like rate shock.

As mentioned previously, Elenchus expressed concerns of the Bary correction's inherent misalignment of revenue and cost-driven price signals that motivated self-generation/grid defection that shifted the burden to other SaskPower customers who

did not incur those costs. This violates SaskPower's objectives of fairness/equity, and economic efficiency, and can lead to stranded assets for the utility.

Implementation of demand charges for all customer classes utilizing coincident peak demand is a potential option but is not economically practical for low demand customers as it requires Advanced Metering Infrastructure (AMI) equipment. Also, price signals can be difficult for customers to respond to appropriately, especially if they have no lead time to reduce their demand.

Another option Elenchus provided would be to assign a portion of demand-related costs within a basic monthly charge. Although this would increase revenue and bill stability, assigning demand-related costs within the basic monthly charge would be inequitable to customers with lower consumption and demand such as low income customers and seasonal customers.

SaskPower's current rate methodology for customers without demand charges, such as the Residential class, does recover demand-related costs within the energy charge, and follows a standardized practice across utilities. Elenchus acknowledges that a change from this practice would provide an inappropriate price signal to customers, particularly in scenarios where costs derived from consumption and demand are greater than variable revenue recovered from the customer.

After reviewing the options SaskPower has available, Elenchus recommended that SaskPower continue to utilize its current rate design practices for customer classes without demand charges, while continuing to identify its rate structure once AMI billing data has been implemented.

E. Financial Reporting Changes during 2024

Minimal financial reporting changes were made within the 2024 Fiscal Period. The following are of note:

- 1) The Streetlight class is reported financially within the Commercial class and the Power – Contract class is being reported financially within the Power class. These amendments align to SaskPower's current financial reporting structure.
- 2) As of April 1, 2019, the federal government implemented a Carbon Tax on fossil fuel emissions based on their carbon pollution pricing system, retroactive to January 1, 2019. The Federal Carbon Tax is based on predetermined emission thresholds set by the federal government on an annual calendar basis.

SaskPower has chosen to recover the Federal Carbon Tax via separate rate riders applied to the customer's energy consumption (kWh) rather than include it within its published rates. Due to this treatment of the carbon tax, no expenses or revenue associated with the carbon tax has ever been included in the Cost of Service Study.

- 3) All Purchased Power Agreement (PPA's) assets are reported as a separate line item within the Cost of Service report, functionalized within Generation.
- 4) As of April 1, 2019, SaskPower adopted IFRS 16, which is a new accounting standard for leases. IFRS 16 provides principles for the recognition, measurement, presentation, and disclosure of leases. Under IFRS 16, the new definition identifies a contract is or contains a lease if the contract conveys a right to control the use of an identified asset for a period of time in exchange for consideration. With the adoption of IFRS 16, SaskPower recognizes the following:
 - Right-of-use assets and liabilities in the consolidated statement of financial position.
 - Depreciation of right-of-use assets and interest expense on the lease liabilities in the consolidated statement of income.
 - Principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the consolidated statement of cashflows.
- 5) Organizational realignment of various Business units occurred throughout 2024 as follows:
 - SaskPower has consolidated NorthPoint, Generation, Transmission and Distribution into one business unit called Operations. Similarly, Asset Management, Technology & Security, and Finance have been consolidated under one business unit called Strategy, Technology & Finance. Procurement and Customer Experience (previously called Customer Services) have also been combined into a business unit called Customer Experience and Procurement. Although these units are now reporting from different areas, their rate base and expenses are still functionalized and classified in the same manner as they were previously.

F. Calculation of the Return on Rate Base

The Return on Rate Base (RORB) is the return, expressed as a percentage, which SaskPower will earn on the net book value of its assets required to produce, transmit and distribute

electricity to its customers, after expenses. SaskPower's RORB is directly tied to its Return on Equity (ROE) performance and is based on achieving its targeted ROE of 8.5%.

The system RORB is calculated based on SaskPower's actual (or forecasted) revenues, expenses, and rate base for the fiscal year. The tables below show the calculation of SaskPower's RORB derived from the 2024 Fiscal Base Cost of Service:

SaskPower Return on Rate Base Inputs/Supporting Calculations as of March 31, 2024
2024 Fiscal Base Embedded Cost of Service Study
(\$ Millions)

Indicator	Item:	2024 Fiscal Base	Calculation Details:
	<u>From SaskPower's Cost of Service</u>		
a)	Total Rate Base	10,912.6	
b)	Electricity Sales Revenue	2,856.1	
c)	Other revenues (incl. Export & Electricity Trading)	<u>283.2</u>	
d)	Total Sales Revenue	<u>3,139.3</u>	b + c
e)	Total Expenses	<u>2,517.1</u>	
f)	Operating Income Before Finance Charges	<u>622.3</u>	d - e
g)	Finance Charges	<u>408.6</u>	
h)	Operating Income	<u>213.7</u>	f - g
i)	Return on Rate Base - Finance Charges	3.7%	g / a
j)	Return on Rate Base - Return	<u>2.0%</u>	h / a
k)	Total Return on Rate Base	<u>5.7%</u>	f / a
	<u>From SaskPower's Financial Statements</u>		
l)	Long Term Debt	7,447.2	
m)	Current Portion of Long Term Debt	(200.0)	
n)	Finance Lease Obligations	850.3	
o)	Current Portion of Lease Obligations	(55.5)	
p)	Short Term Advances	910.1	
q)	Debt Retirement Funds	2,236.8	
r)	Cash & Cash Equivalents	<u>593.0</u>	
s)	Total Debt	<u>11,781.9</u>	l + m + n + o +
t)	Retained Earnings	122.9	
u)	Equity Advances	374.0	
v)	Total Equity	<u>496.9</u>	t + u
w)	Total Debt & Equity	<u>12,278.9</u>	s + v
x)	Debt %	96.0%	s / w
y)	Equity %	4.0%	v / w

SaskPower 2024 Fiscal Base Return on Rate Base as of March 31, 2024
2024 Fiscal Base Embedded Cost of Service Study
(\$ Millions)

	Amount	Capital Structure	Cost of Capital	Component Weighted Cost of Capital
Debt	11,781.9	95.95% *	3.90%	= 3.74%
Equity	496.9	4.05% *	48.38%	= 1.96%
Total	12,278.9	Return on Rate Base		5.70%

Please note that within the Cost of Service Return on Equity (ROE) calculation, unlike within the ROE calculation within SaskPower's Financial Statements, equity earnings is not included.

G. Cost of Service to Audited Financial Statements Reconciliation

Due to differences between IFRS accounting standards and the National Association of Regulatory Utility Commissioner's (NARUC) electric utility cost allocation standards, an Income Statement and a Balance Sheet reconciliation that highlights the difference between the two is included below:

Fiscal Base Income Statement - Cost of Service to Audited Financial Statements Reconciliation (\$ Millions)			
	2024 Fiscal Base		
	Income Statement	Adjustment	Cost of Service
REVENUE			
Saskatchewan Sales	\$2,856.1	\$0.0	\$2,856.1
Federal Carbon Revenue	\$239.5	(\$239.5)	\$0.0
Export + Electricity Trading	\$128.9	(\$128.9)	\$0.0
Other Income (Does Not Include SPI Equity Earnings)	\$154.4	(\$154.4)	\$0.0
Total Revenue	\$3,378.9	(\$522.8)	\$2,856.1
EXPENSES			
Fuel & Purchased Power			
Fuel	\$583.1		\$583.1
Purchased Power	\$388.3		\$388.3
Federal Carbon Charge Expense	\$268.8	(\$268.8)	\$0.0
Total Fuel and Purchased Power	\$1,240.2	(\$268.8)	\$971.5
Less Export & Net Electricity Trading Revenue		(\$128.9)	(\$128.9)
Total Fuel & Purchased Power After Export Revenue	\$1,240.2	(\$397.6)	\$842.6
Total OM&A	\$810.7		\$810.7
Total Depreciation & Other Expenses	\$642.9		\$642.9
Finance Charges	\$408.6	(\$408.6)	\$0.0
Total Taxes	\$92.0		\$92.0
Total Other Income	(\$154.4)	(\$154.4)	(\$154.4)
Total Expenses	\$3,040.1	(\$960.6)	\$2,233.8
Operating Income	\$338.8	\$437.8	\$622.3
Rate Base			\$10,912.6
Return on Rate Base			5.70%

Reconciliation to Audited Financial Statements:

Operating Income for the Cost of Service before Adjustments	\$622.3
add: Federal Carbon Tax Revenue	\$239.5
less: Finance Charges	(\$408.6)
Foreign Exchange Gains/Losses	\$0.2
Federal Carbon Charge Expense	(\$268.8)
Operating Income Before Adjustments	\$184.6

Net Income as per the Audited Financial Statements	\$184.6

** numbers may differ due to immaterial rounding

Fiscal Base Balance Sheet - Cost of Service to Audited Financial Statements Reconciliation
(\$ Millions)

Reconciliation to Audited Financial Statements:	2024 Fiscal Base
Rate Base from the Cost of Service before Adjustments <i>(see Schedule 1.0)</i>	\$10,912.6
add: Current Assets Net of Inventories, Prepaid, & Risk Mgmt Assets	\$843.3
Equity Investments	\$0.0
Debt Retirement Funds	\$799.7
Construction in Progress	\$1,295.3
Risk Management Assets (unrealized)	\$6.3
less: Working Capital Adj	(\$112.8)
Total Assets as per the Audited Financial Statements	\$13,744.4

* numbers may differ due to immaterial rounding

II. SUMMARY OF RESULTS

Tables 1, 2, and 3 outline the summary results from the 2024 Fiscal Base Cost of Service Study.

- **Table 1 – Summary of Functionalized Revenue Requirement**
This table identifies the cost of service by function (Generation, Transmission, Distribution, and Customer Service).
- **Table 2 – Summary of Classified Revenue Requirement**
This table identifies the cost of service by billing component for each customer class. The breakdown mimics the rate structure for all customer classes.
- **Table 3 – Summary of Revenue to Revenue Requirement Ratios**
This table displays the breakdown of Revenue to Revenue Requirement Ratio by customer class.

Table 1 – Summary of Functionalized Revenue Requirement

Summary of Functionalized Revenue Requirement by Customer Class									
2024 Fiscal Base Embedded Cost of Service Study									
(\$ Millions)									
Customer Class	Total Company (\$)	Generation		Transmission		Distribution		Customer Service	
		(\$)	(%)	(\$)	(%)	(\$)	(%)	(\$)	(%)
Residential	644.4	303.9	47.2%	69.2	10.7%	206.7	32.1%	64.7	10.0%
Farms	209.3	113.2	54.1%	23.4	11.2%	62.7	29.9%	10.1	4.8%
Commercial	544.8	318.4	58.4%	62.7	11.5%	152.8	28.0%	11.0	2.0%
Power	855.3	737.5	86.2%	107.9	12.6%	5.2	0.6%	4.8	0.6%
Oilfields	494.3	330.5	66.9%	54.9	11.1%	101.8	20.6%	7.1	1.4%
Reseller	107.9	93.1	86.3%	14.5	13.4%	0.2	0.2%	0.1	0.1%
Total	2,856.1	1,896.6	66.4%	332.6	11.6%	529.2	18.5%	97.6	3.4%

Table 2 – Summary of Classified Revenue Requirement

Summary of Classified Revenue Requirement by Customer Class 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)							
Customer Class	Total Company (\$)	Demand Related		Energy Related		Customer Related	
		(\$)	(%)	(\$)	(%)	(\$)	(%)
Residential	644.4	285.2	44.3%	179.6	27.9%	179.6	27.9%
Farms	209.3	101.0	48.2%	71.1	34.0%	37.2	17.8%
Commercial	544.8	273.5	50.2%	205.9	37.8%	65.4	12.0%
Power	855.3	330.4	38.6%	519.9	60.8%	5.0	0.6%
Oilfields	494.3	234.3	47.4%	231.0	46.7%	29.0	5.9%
Reseller	107.9	51.1	47.3%	56.7	52.5%	0.1	0.1%
Total	2,856.1	1,275.5	44.7%	1,264.3	44.3%	316.3	11.1%

Table 3 – Summary of Revenue to Revenue Requirement Ratios

Summary of Revenue to Revenue Requirement Ratios 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)			
Customer Class	Revenue (\$)	Revenue Requirement (\$)	Revenue to Revenue Requirement Ratio
Residential	631.6	644.4	0.98
Farms	198.0	209.3	0.95
Commercial	556.6	544.8	1.02
Power	894.4	855.3	1.05
Oilfields	469.9	494.3	0.95
Reseller	105.7	107.9	0.98
Total (System)	2,856.1	2,856.1	1.00

III. COST OF SERVICE METHODOLOGY

The study follows a five-step process:

- The first step is to **identify** in detail the accounting costs that are to be allocated to customer classes.
- The second step is to **functionalize** the costs between generation, transmission, distribution, and customer services functions.
- The third step is to **classify** each set of functionalized costs into demand, energy, and customer components.
- The fourth step is to **allocate** the functionally classified costs among the several customer classes.
- The fifth step is to **compare** between the allocated costs and the revenues collected from the customer classes to arrive at the revenue to cost ratios.

STEP 1: IDENTIFICATION

The initial step is to identify the accounting costs to be included in the Cost of Service Study. SaskPower's Finance Business Unit supplies the 2024 Fiscal Year End Consolidated Financial Summary.

Three types of accounts are separately identified in detail:

1. Rate Base Items – investments and liabilities as reported in SaskPower's Balance Sheet. Please refer to **Schedule 1.0** for summary of these items as well as the historical data for the 2024 Fiscal Base Year. Data is reported for the year end in the following categories:

- Plant in Service
- Accumulated Depreciation
- Allowance for Working Capital
- Inventories
- Other Assets

Plant in Service is reported in more detail by function: Generation - by type of generation, Transmission - by voltage level, Distribution Plant - by type of plant, and General & Intangible Plant - by primary usage (unused land, buildings, office furniture and equipment, vehicles & equipment, computer development & equipment, communication, protection & control, and tools and equipment).

Contributions in Aid of Construction were previously netted against Fixed Assets as part of the Rate Base and amortized over the estimated service life of the related asset. The amortization of these contributions was netted against Depreciation Expense under GAAP. However, with the adoption of IFRS accounting standards in 2011, Contributions

in Aid of Construction is recognized immediately as Other Income when the related fixed asset is available for use.

2. Revenue Requirement – this is a calculation of annual costs (from SaskPower’s Income Statement) plus the Return on Rate Base (calculated as Rate Base multiplied by the system average Return on Rate Base percentage). The system average Return on Rate Base is equal to total revenue minus total expenses divided by the total rate base. Please refer to **Schedule 1.0** for a summary of these items as well as the historical data for the 2024 Fiscal Base Year. Data is reported for the year end in the following categories:

- Fuel
- Purchased Power
- Export Revenue (Credit)
- Operating, Maintenance, & Administration (OM&A)
- Depreciation and Depletion
- Corporate Capital Tax
- Grants In Lieu of Taxes
- Miscellaneous Tax
- Other Operating Revenues (Credit)
- Return on Rate Base (Rate Base multiplied by the system average Return on Rate Base)

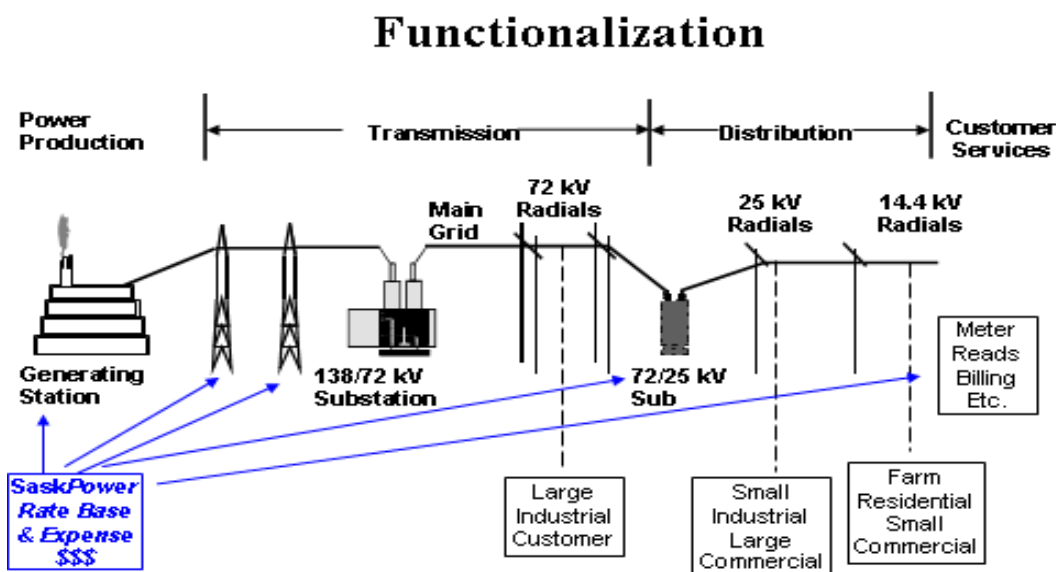
3. Revenue Items - annual domestic sales revenues as reported on SaskPower’s Income Statement. For forecast (Test) years, the SaskPower Load & Revenue Forecasting department provides a projection of net sales within Saskatchewan. **Schedule 7.0** provides a summary by customer class of the actual revenues for the 2024 Fiscal Base Year.

STEP 2: FUNCTIONALIZATION

The second step is to functionalize all accounting costs, in terms of plant and expenses into the major functions of SaskPower's integrated electric system. Please refer to **Figure 1** for a schematic of the process. Rate base and expenses are assigned to the following functions and sub functions:

1. Generation Load Losses Scheduling & Dispatch Regulation & Frequency Response Spinning Reserve Supplementary Reserve Planning Reserve Reactive Supply Grants in Lieu of Taxes	3. Distribution Area Substations Distribution Mains Urban Laterals Rural Laterals Transformers Services Instrument Transformers Meters Streetlights Customer Contributions
2. Transmission Main Grid 230kV & 138kV Lines Radials 138kV/72kV Substations 72kV Lines Radials	4. Customer Service Metering Services Meter Reading Billing & Customer Accounts Customer Collecting Service & Support Customer Strategy & Planning

Figure 1: Functionalization Schematic



Please refer to **Schedules 2.00 through to 2.36** for the functionalization of the financial accounting details. A summary of the functionalization methodology is summarized below for rate base and revenue requirement which includes annual expense items from the income statement and return on rate base.

1. Rate Base Items

1.1 - Plant in Service & Accumulated Depreciation

- **SaskPower Generation, Transmission, and Distribution:**
All the rate base accounts are functionalized based on the plant designation; generation plant is functionalized entirely to the generation function; transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for Wind Projects are included within SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.
- **Coal Reserves:**
SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

-
- **Shand Greenhouse:**
The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.
 - **Purchased Power Agreements:**
The assets associated with Purchased Power Agreements are functionalized to generation.
 - **Meters and Instrument Transformers:**
Meters and instrument transformers are included in the meters and instrument transformers sub-function within distribution.
 - **General Plant - Unused Land:**
The functionalization and sub-functionalization of unused land is done using OM&A.
 - **General Plant – Right of Use Land:**
The functionalization and sub-functionalization of right-of-use land is done using OM&A.
 - **General Plant – Buildings:**
The functionalization and sub-functionalization of the SaskPower head office building and all other buildings is done using OM&A expense.
 - **General Plant – Right of Use Buildings:**
The functionalization and sub-functionalization of right-of-use buildings is done using OM&A expense derived from buildings, excluding Head Office, Research & Development, Storage and Residential Buildings.
 - **General Plant - Office Furniture & Equipment:**
The functionalization and sub-functionalization of office furniture and equipment utilizes OM&A for buildings.
 - **General Plant - Vehicles & Equipment:**
The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit centre. The asset values for vehicles and equipment are then prorated to sub-functions within each function using OM&A expense.
 - **General Plant - Computer Development & Equipment:**

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application by application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using OM&A expense.

- **General Plant - Communication, Protection & Control Equipment:**
Communication, Protection & Control Equipment is functionalized to generation, transmission, distribution, and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.
- **General Plant - Tools & Equipment:**
The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using OM&A expense.

1.2 - Allowance for Working Capital

- The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working capital is calculated as 12.5% of the sum of OM&A expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.3 - Inventories

- SaskPower accounting records summarize inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within the generation, transmission and distribution functions using OM&A.

1.4 - Other Assets

- Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:
 - **Natural gas / coal-related:**
Functionalized to generation.

- **Employee-related:**
Functionalized using head count by Business Unit / Support Group.
- **Insurance expense-related:**
Functionalized using information provided from SaskPower's risk management staff.
- **Miscellaneous:**
Prorated to sub-functions within each function using OM&A expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below:

2.1 - Fuel Expense SaskPower Units

- The fuel expense for SaskPower units is functionalized 100% to generation.

2.2 - Purchased Power and Import

- The purchased power expense is functionalized 100% to generation.

2.3 - Export & Net Electricity Trading Revenue

- Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.4 - Operating, Maintenance & Administration (OM&A) Expense

- **Power Production Business Unit:**
The OM&A expenses for the Power Production Business Unit and Purchased Power Agreements (PPAs) are functionalized to Generation.
- **Transmission & Distribution Business Unit:**
A small amount of the Transmission and Distribution Business Unit's OM&A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the OM&A expense for the Business Unit is split to transmission and distribution using cost centre reports.
 - Transmission OM&A is sub-functionalized by separating transmission OM&A expense into line and station-related functions. The line-related

OM&A is sub-functionalized to main grid, 230 & 138 kV radials, & 72 kV radials using the transmission line assets plant in service by sub-function. The station-related OM&A expense is sub-functionalized using the station assets plant in service by sub-function.

- Distribution OM&A is functionalized to distribution and customer services using a combination of staff input and detailed cost centre OM&A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions.
 - Metering Services OM&A was moved from Customer Services to Transmission & Distribution in 2013 but is still functionalized to Customer Services.
- **Customer Services Business Unit:**
The OM&A expense for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre OM&A reports.
 - **Customer Services - Bad Debt Expense:**
The Bad Debt expense is assigned to the customer collections sub-function within the Customer Services function.
 - **President / Board:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.
 - **Corporate & Financial Services:**
Functionalized based on employee head count by Business Unit and Support Group.
 - **Corporate & Financial Services – Insurance Premiums & Insurable Losses:**
Functionalized based on breakdown from SaskPower Risk Management & Insurance department staff.
 - **Asset Management, Planning & Sustainability:**
Asset Management, Planning & Sustainability was previously called Resource Planning/Planning, Environment and Regulatory Affairs (PERA). It is made up of four cost centres: Generation Asset Management and Supply Planning, Transmission Asset Management and Planning, Distribution Asset Management

and Planning, and Environment. The Planning cost centres are assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Environment cost centre moved to Resource Planning from Human Resources in 2015 and is allocated based on an employee analysis which was done by SaskPower Environment department staff. The Shand Greenhouse is embedded within the Environment cost centre and is functionalized to Generation.

- **Carbon Capture & Storage (CCS):**

The OM&A expense for CCS is embedded within the Power Production business unit and is functionalized to Generation.

- **Small Modular Reactors (SMR) Consortium:**

The OM&A expense for Small Modular Reactors (SMR) is embedded within the Asset Management, Planning, & Sustainability business unit and is functionalized to Generation.

- **General Council / Land:**

Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.

- **Safety:**

Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the OM&A sub-functionalization within each function.

- **Technology & Security (formerly Corporate Information & Technology):**

Technology & Security OM&A expense is separated into personal computer-related and Business Unit-related functions. The personal computer-related is functionalized using employee headcount. The Business Unit-related function is functionalized using information from the cost centre report. Sub-functionalization is completed using OM&A within each function.

- **Human Resources:**

Functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function.

- **Commercial & Industrial Operations:**

Commercial & Industrial Operations is department made up of three cost centres: Coal Combustion Products, Fuel Supply and NorthPoint. The Customer Relations

cost centre was previously located here but has been since relocated back to Customer Services and continues to be functionalized to Customer Service. Coal Combustion, along with Individual Purchased Power cost centre was recently relocated to Finance, but is being tracked and reported in the Power Production business unit and continues to be functionalized to Generation. The Fuel Supply cost centre was previously reported in Resource Planning and continues to be functionalized to Generation. NorthPoint previously was reported in Operations and continues to be functionalized to Generation.

- **Procurement & Supply Chain**

Procurement & Supply Chain is made up of three cost centres: Supply Chain, Properties & Shared Services, and Contract Management. Supply Chain and Properties & Shared Services are functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function. Contract Management is functionalized to Generation. The Logistics area was moved to Procurement & Supply Chain in 2015 from Distribution; however, based on Logistics' close relation to Distribution, their OM&A is still being calculated and functionalized within Distribution.

2.5 - Depreciation & Depletion

- The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.6 - Corporate Capital Tax

- Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.7 - Grants in Lieu of Taxes

- Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.8 – Miscellaneous Tax

- The miscellaneous tax expenses have been grouped into the following categories using cost centre reports:
 - **Power production-related:**
Functionalized to generation.
 - **Corporate-related:**
Functionalized using total OM&A expense.

2.9 - Other Income

- Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.
 - **Customer services payment income:**
Assigned to the billing, customer accounts and collections sub-functions within customer services.
 - **Meter reading income:**
Assigned to the meter reading sub-function within the customer services function.
 - **Transmission-related income:**
Assigned to sub-functions within the transmission function using transmission OM&A expense.
 - **Distribution-related income:**
Assigned to sub-functions within the distribution function using distribution OM&A expense.
 - **Miscellaneous Other Income:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.
 - **Customer Contribution Revenue**
As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.
 - **Green power premium:**
Assigned to the load and losses sub-functions within generation using fuel expense.
 - **Flyash & Wind Power Sales:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **CO² Sales & Penalties:**
Assigned to the load and losses sub-functions within generation using fuel expense.
- **Renewable Energy Credits:**
Assigned to the load and losses sub-functions within generation using fuel expense.

2.10 - Return on Rate Base

- The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

STEP 3: CLASSIFICATION

The classification process splits the functionalized costs into the parameters of service, which are:

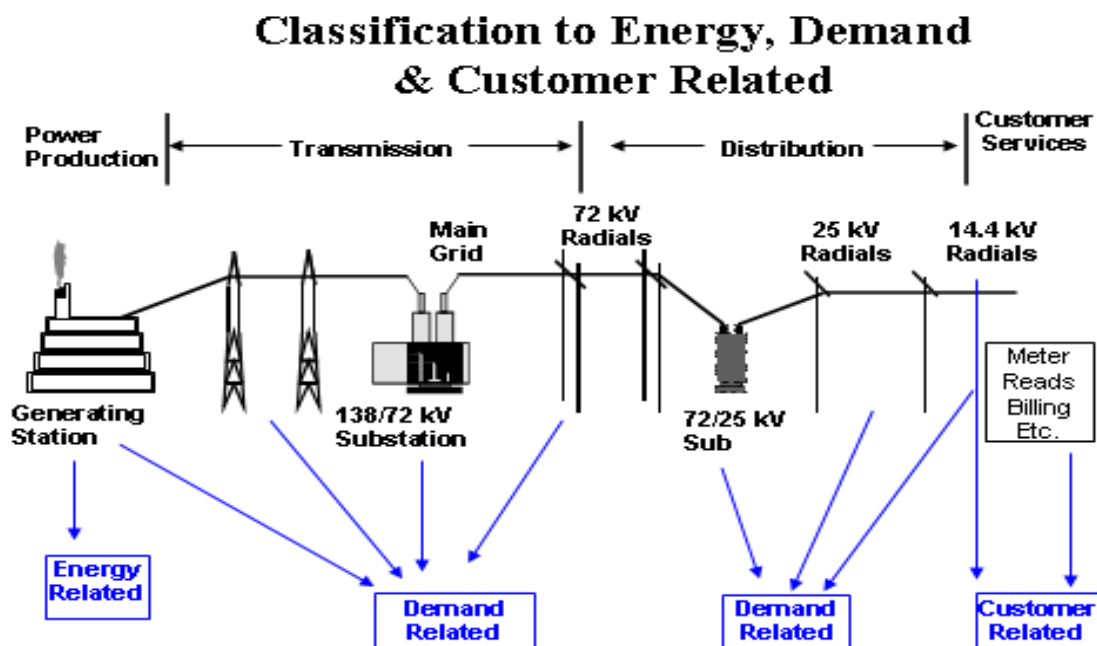
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission, and distribution systems.

Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.

Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

Figure 2 below presents a schematic of the classification process.

Figure 2: Classification Schematic



A discussion of the classification of each of the functionalized costs is as follows:

- **Generation:**

SaskPower generation rate base and expense is classified as either demand or energy-related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Average & Excess Demand method (AED), based on the NARUC Electric Utility Cost Allocation manual. The rationale behind AED is that a utility's average annual demand is required to meet its energy requirements, and any demand in excess of that average is required to meet its peaking requirements.

The assets and expenses associated with Purchased Power Agreements (PPAs) are classified to demand and energy using the capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation

operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The expenses and income associated with fly-ash sales (now called Coal Combustion Products) are classified as energy-related.

The classification of all wind generation rate base and expenses are also classified to energy and demand using the Average & Excess Demand method (AED). This is a change from previous years when SaskPower planning staff classified the wind units based on planning studies regarding the capacity value of wind generation.

Diesel units continue to be classified as 100% to demand.

- **Coal Reserves:**

SaskPower coal reserves are classified as energy-related.

- **Shand Greenhouse:**

The Shand Greenhouse assets, OM&A and depreciation expenses are classified using the classification of all SaskPower generation.

- **NorthPoint:**

The OM&A expense and other revenue associated with NorthPoint are classified 100% as energy-related.

- **Transmission:**

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% as demand-related.

- **Distribution:**

Substations are classified 100% as demand-related costs. Three phase feeders are classified 100% as demand-related costs.

Both urban and rural single-phase primary lines are classified 30% to demand-related and 70% to customer-related costs. Line transformers are classified 65% to demand-related and 35% to customer-related cost based upon Minimum System Method (MSM). As indicated in part D of the introduction, classification changes utilizing the MSM for urban and rural single-phase primary lines (laterals) and line transformers were recommended by the Elenchus Cost of Service study in 2023 and implemented within this Cost of Service Study.

All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as a customer-related costs.

- **Customer:**
Customer-related costs are classified 100% as customer-related.

The results of the functionalization and classification (or functional classification) of rate base, expense, return on rate base, and revenue requirement are summarized in ***Schedules 2.00 through to 2.36.***

STEP 4: ALLOCATION

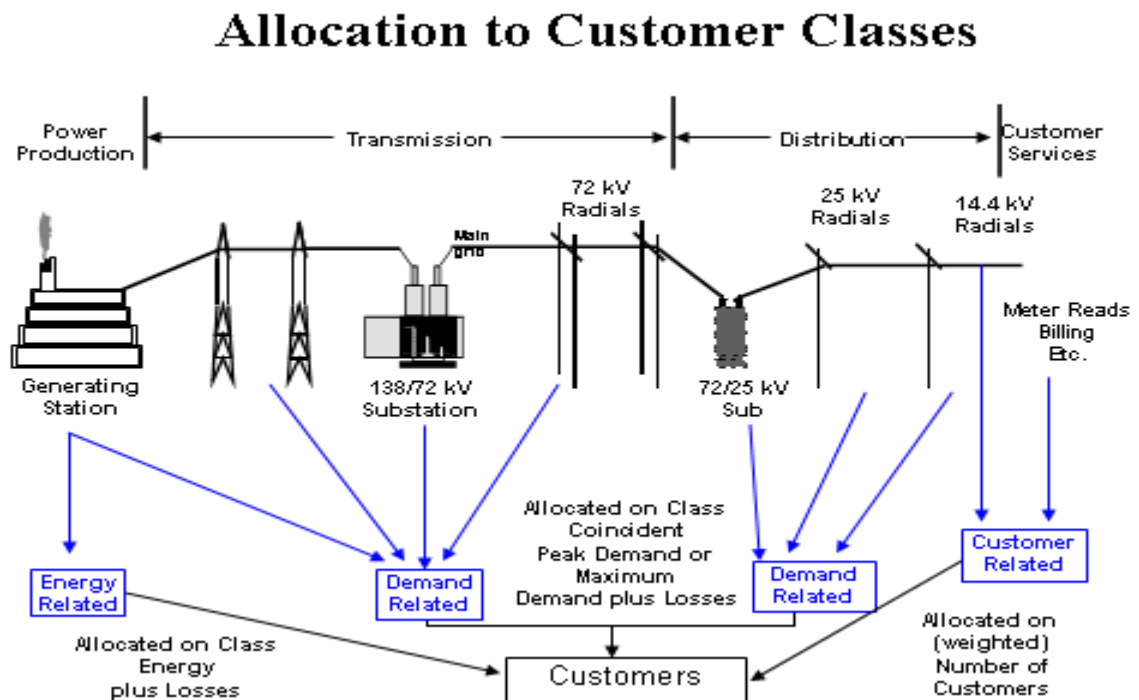
Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated:

- Residential
- Farms
- Commercial
- Power
- Oilfields
- Reseller

Figure 3 presents a schematic of the allocation process. The methodologies chosen by SaskPower for allocation are summarized in **Schedule 3.0**. The core data used in the development of allocation factors can be found in **Schedule 4.0**.

Figure 3: Allocation Schematic



An explanation of the allocation process by function is as follows:

- **Generation:**

The energy-related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand-related rate base and expenses are allocated by the Two CP (2CP) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May, and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

- **Transmission:**

All transmission functions are classified as demand and are allocated using the 2CP method as aforementioned.

- **Distribution:**

The demand functions within distribution use a combination of the 2CP method and the Maximum Diversified Class Demands (MDD) method. The MDD method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demand of a rate class, regardless of when it occurs, during a specified period, to the sum of all the class peaks, similarly determined. Only the transformers function uses the MDD methodology. All other functions use the 2CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer-related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight-related rate base and expenses are allocated directly to streetlights.

- **Customer Services:**

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

- **Customer Contributions:**

These contributions are allocated back directly to the customer classes which made the contribution.

- **Load Data:**

Customer load data is obtained for each class from the best available sources. Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The results for the customer types in each of these classes are then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.

Power class loads were analyzed based on hourly meter readings from actual customers' interval metered sites.

- **Loss Study:**

The purpose of a loss study is to properly quantify and assign the electrical energy and demand losses in the various segments of the system to the appropriate customer class. The starting point is the total energy loss in GWh, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

- **Allocators:**

The allocation factors are summarized in **Schedules 5.0 to 5.3**. The functionalization and classification of the revenue requirement is summarized in **Tables 1 and 2** (Summary of Results section), and the details are in **Schedules 6.0 to 6.3**.

STEP 5: COMPARE

The allocated rate base, allocated expenses and class revenue are the foundation for calculating the revenue to revenue requirement (R/RR) ratio by class. A R/RR measure of 1.00 indicates that the revenues received from a customer class exactly matches the costs of providing it electrical service; or, to put it simply, a customer is paying the amount it costs SaskPower to provide them with service. An R/RR below 1.00 indicates that a customer class is paying less than the cost to serve while an R/RR above 1.00 indicates that a customer class is paying more than the cost to serve. On a system-wide basis, the ratio must equal 1.00.

In response to comments of cross-subsidization between SaskPower's customer classes, external consultants have advised SaskPower that R/RR ratios close to 1.00 are deemed to be reasonable. Cost allocation studies of shared assets utilized by various customer groups represents the best and most current information available but is subject to fluctuations and uncertainty from year to year. A range of acceptable R/RR ratios of 0.95

to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that a customer is paying their fair share of costs. As a result, a R/RR ratio that is slightly above or below 1.00 does not demonstrate that one customer class subsidizes or receives a subsidy from other customer classes if it falls within the acceptable range. In conclusion, if the R/RR ratios are within the acceptable range, the results are deemed to be reasonable and there is no refutable evidence of cross-subsidization.

R/RR ratios are determined by comparing the revenue collected from each class to the revenue required to serve the customer class. The revenue requirement for each customer class is calculated as the allocated rate base multiplied by the system return on rate base plus allocated expenses. Please refer to **Table 3** in the Summary of Results section for an R/RR ratio breakdown by customer class.

It is important to note that R/RR ratios are not static. Each year SaskPower rebuilds the cost of service model using the latest annual financial information and customer revenue and load data. As such, cost of service results will vary from year to year for several reasons, including:

- 1) Class Revenue Changes
- 2) Class Revenue Requirement Changes, due to:
 - Non-uniform escalation of generation, transmission, distribution & customer service costs (e.g., capital expenditures, fuel & purchased power, OM&A, and depreciation expense)
 - Changes to cost of service methodology
 - Changes to class demand (e.g., customer load factors) at system peak, due to:
 - Economic conditions
 - Mechanical failures
 - Unforeseen shutdowns
 - Operational changes
 - Variations in weather patterns

R/RR ratios in Base (actual) years are dependent on the actual annual revenue and the calculated revenue requirement derived from the Cost of Service Study which may reflect any, or all, of the above conditions.

In Test (forecast) years, SaskPower attempts to set the R/RR ratios between 0.98 to 1.02 using assumptions based on a “most likely” scenario, to stabilize rate designs and protect all customers from outlying or anomalous conditions that may occur.

IV. SUPPORTING SCHEDULES

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)									
Rate Base and Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Rate Base									
Plant in Service (Schedule 1.1)	19,021.2	9,440.6	49.6%	3,606.5	19.0%	5,774.5	30.4%	199.6	1.0%
Accumulated Depreciation (Schedule 1.2)	(8,729.3)	(5,201.8)	59.6%	(1,159.2)	13.3%	(2,314.5)	26.5%	(53.8)	0.6%
Allowance For Working Capital	112.8	61.9	54.9%	16.2	14.3%	23.8	21.1%	11.0	9.8%
Inventories (Schedule 1.3)	361.7	143.3	39.6%	86.1	23.8%	132.6	36.7%	(0.3)	-0.1%
Other Assets (Schedule 1.3)	146.2	92.4	63.2%	16.7	11.4%	24.6	16.8%	12.5	8.5%
Total Rate Base	10,912.6	4,536.4	41.6%	2,566.3	23.5%	3,641.0	33.4%	169.0	1.5%
Revenue Requirement									
Fuel Expense SaskPower Units	583.1	583.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	388.3	388.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(128.9)	(128.9)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating, Maintenance & Administration (Schedule 1.4)	810.7	436.8	53.9%	115.8	14.3%	170.9	21.1%	87.2	10.8%
Depreciation & Depletion (Schedule 1.5)	642.9	341.4	53.1%	100.1	15.6%	190.5	29.6%	10.9	1.7%
Corporate Capital Tax	57.1	23.5	41.2%	13.6	23.8%	19.2	33.6%	0.8	1.4%
Grants in Lieu of Taxes	34.0	34.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	0.8	0.8	96.8%	0.0	1.0%	0.0	1.4%	0.0	0.7%
Other Income (Credit) (Schedule 1.6)	(154.4)	(41.2)	26.7%	(43.2)	28.0%	(59.0)	38.2%	(11.0)	7.1%
Return on Rate Base @ 5.70%	622.3	258.7	41.6%	146.3	23.5%	207.6	33.4%	9.6	1.5%
Total Revenue Requirement	2,856.1	1,896.6	66.4%	332.6	11.6%	529.2	18.5%	97.6	3.4%

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details PLANT IN SERVICE 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)						
Asset Categories	SaskPower Total	Functional Breakdown				
		Generation		Transmission	Distribution	Customer Service
Generation Assets						
Power Production	7,907.0	7,907.0	100.0%	-	-	0.0%
Power Production - PPA	1,017.1	1,017.1	100.0%	-	-	0.0%
Coal Reserves	72.4	72.4	100.0%	-	-	0.0%
Shand Greenhouse	6.0	6.0	100.0%	-	-	0.0%
Total Generation Assets	9,002.5	9,002.5	100.0%	-	-	0.0%
Transmission Assets						
Transmission Assets	3,290.6	6.7	0.2%	3,250.8	33.1	0.0%
Total Transmission Assets	3,290.6	6.7	0.2%	3,250.8	33.1	0.0%
Distribution Assets						
Distribution Assets	5,250.7	-	0.0%	-	5,250.7	100.0%
Meters	117.4	-	0.0%	-	117.4	100.0%
Instrument Transformers	20.3	-	0.0%	-	20.3	100.0%
Total Distribution Assets	5,388.4	-	0.0%	-	5,388.4	100.0%
General Plant Assets						
Unused Land	2.3	1.3	53.9%	0.3	0.5	21.1%
Right of Use Land	9.1	4.9	53.9%	1.3	1.9	21.1%
Buildings	638.5	201.7	31.6%	126.9	169.7	26.6%
Right of Use Buildings	7.0	2.0	29.1%	1.4	1.9	27.6%
Office Furniture & Equipment	55.7	17.6	31.6%	11.1	14.8	26.6%
Vehicles & Equipment	221.2	33.3	15.1%	73.5	96.9	43.8%
Computer Development & Equipment	197.8	106.6	53.9%	29.9	38.4	19.4%
Communication, Protection & Control	184.1	57.2	31.1%	103.1	20.9	11.4%
Tools & Equipment	24.0	6.9	28.6%	8.2	8.0	33.2%
Total General Plant Assets	1,339.8	431.4	32.2%	355.7	353.1	26.4%
Total Plant in Service	19,021.2	9,440.6	49.6%	3,606.5	5,774.5	30.4%

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details ACCUMULATED DEPRECIATION 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)						
Asset Categories	SaskPower Total	Functional Breakdown				
		Generation		Transmission	Distribution	Customer Service
Generation Assets						
Power Production	(4,345.5)	(4,345.5)	100.0%	-	0.0%	-
Power Production - PPA	(611.1)	(611.1)	100.0%	-	0.0%	-
Coal Reserves	(47.1)	(47.1)	100.0%	-	0.0%	-
Shand Greenhouse	(4.1)	(4.1)	100.0%	-	0.0%	-
Total Generation Assets	(5,007.8)	(5,007.8)	100.0%	-	0.0%	-
Transmission Assets						
Transmission Assets	(1,006.1)	(1.6)	0.2%	(987.2)	98.1%	-
Total Transmission Assets	(1,006.1)	(1.6)	0.2%	(987.2)	98.1%	-
Distribution Assets						
Distribution Assets	(2,063.6)	-	0.0%	-	0.0%	-
Meters	(79.9)	-	0.0%	-	0.0%	-
Instrument Transformers	(15.2)	-	0.0%	-	0.0%	-
Total Distribution Assets	(2,158.7)	-	0.0%	-	0.0%	-
General Plant Assets						
Unused Land	-	-	0.0%	-	0.0%	-
Right of Use Land	(3.4)	(1.8)	53.9%	(0.5)	14.3%	(0.4)
Buildings	(70.3)	(25.5)	36.2%	(13.1)	18.6%	(14.3)
Right of Use Buildings	(4.6)	(1.3)	29.1%	(0.9)	20.7%	(1.0)
Office Furniture & Equipment	(26.3)	(9.5)	36.2%	(4.9)	18.6%	(5.3)
Vehicles & Equipment	(130.5)	(18.1)	13.9%	(44.0)	33.7%	(10.5)
Computer Development & Equipment	(168.4)	(88.2)	52.4%	(26.4)	15.7%	(19.6)
Communication, Protection & Control	(141.3)	(44.6)	31.6%	(77.7)	55.0%	(2.3)
Tools & Equipment	(11.9)	(3.3)	28.0%	(4.5)	37.7%	(0.4)
Total General Plant Assets	(556.7)	(192.3)	34.6%	(172.0)	30.9%	(53.8)
Total Accumulated Depreciation	(8,729.3)	(5,201.8)	59.6%	(1,159.2)	13.3%	(53.8)

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details INVENTORIES 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)						

	SaskPower Total	Functional Breakdown				
		Generation	Transmission	Distribution	Customer Service	
Inventories						
Power Production - Repair Stores	124.9	124.9	-	-	0.0%	0.0%
Power Production - Fuel	19.9	19.9	-	-	0.0%	0.0%
Transmission & Distribution	219.7	-	86.5	133.2	60.6%	0.0%
Miscellaneous (Computers, Power Shop)	(2.8)	(1.5)	(0.4)	(0.6)	21.1%	10.8%
Total Inventories	361.7	143.3	86.1	132.6	36.7%	-0.1%

Functionalization of Financial Account Details OTHER ASSETS 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)						

	SaskPower Total	Functional Breakdown				
		Generation	Transmission	Distribution	Customer Service	
Other Assets						
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	26.3	26.3	-	-	0.0%	0.0%
Intangible Assets	82.2	44.3	11.7	17.3	21.1%	8.8
Prepaid Expenses - Insurance	4.2	3.8	0.2	0.2	5.3%	0.0
Miscellaneous Prepaid Expenses	33.5	18.0	4.8	7.1	21.1%	3.6
Total Generation Expenses	146.2	92.4	16.7	24.6	16.8%	12.5

Schedule 1.4: Functionalization of Financial Account Details – OM&A Expense

Functionalization of Financial Account Details OM&A EXPENSES 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)									
Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	226.4	226.4	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	30.5	30.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchase Power Agreements (PPA)	13.0	13.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	269.9	269.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution Expenses									
Planning Support	24.3	13.2	54.3%	10.7	44.2%	0.1	0.4%	0.3	1.1%
Transmission Including 230/138 & 72 kV Radials	67.4	-	0.0%	67.4	100.0%	-	0.0%	-	0.0%
Distribution	120.2	-	0.0%	-	0.0%	120.2	100.0%	-	0.0%
Customer Services	8.8	-	0.0%	-	0.0%	-	0.0%	8.8	100.0%
Metering Services	5.6	-	0.0%	-	0.0%	-	0.0%	5.6	100.0%
Total Transmission & Distribution Expenses	226.3	13.2	5.8%	78.2	34.5%	120.3	53.2%	14.6	6.5%
Customer Services Expenses									
Meter Reading	11.9	-	0.0%	-	0.0%	-	0.0%	11.9	100.0%
Billing Services	3.2	-	0.0%	-	0.0%	-	0.0%	3.2	100.0%
Collections/Special Collections	1.6	-	0.0%	-	0.0%	-	0.0%	1.6	100.0%
Bad Debt Expense	8.3	-	0.0%	-	0.0%	-	0.0%	8.3	100.0%
Marketing & Sales	2.6	-	0.0%	-	0.0%	-	0.0%	2.6	100.0%
Demand Side Management	8.3	8.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	21.5	-	0.0%	-	0.0%	-	0.0%	21.5	100.0%
Total Customer Services Expenses	57.5	8.3	14.5%	-	0.0%	-	0.0%	49.1	85.5%
Support Group Expenses									
President / Board	2.2	1.2	53.9%	0.3	14.3%	0.5	21.1%	0.2	10.8%
Corporate & Financial Services (C&FS)	11.3	5.0	44.0%	2.1	18.6%	2.8	25.0%	1.4	12.4%
C&FS - Insurance Premiums & Insurable Losses	19.2	17.3	90.0%	0.8	4.0%	1.0	5.3%	0.1	0.6%
Asset Management, Planning, & Sustainability	12.8	6.6	51.1%	2.3	18.3%	3.1	24.5%	0.8	6.1%
Integrated Carbon Capture & Sequestration	23.9	23.9	100.0%	-	0.0%	-	0.0%	-	0.0%
SMR Consortium	0.1	0.1	100.0%	-	0.0%	-	0.0%	-	0.0%
General Council / Land	7.3	4.0	53.9%	1.0	14.3%	1.5	21.1%	0.8	10.8%
Safety	6.8	3.3	48.4%	1.2	17.5%	1.7	24.3%	0.7	9.7%
Corporate Information & Technology	102.6	48.2	47.0%	17.9	17.4%	23.8	23.2%	12.7	12.4%
Human Resources	32.3	12.5	38.7%	6.9	21.4%	9.4	29.2%	3.5	10.7%
Commercial & Industrial Operations	11.5	11.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Procurement & Supply Chain	26.8	11.8	44.0%	5.0	18.6%	6.7	25.0%	3.3	12.4%
Total Support Group Expenses	257.0	145.3	56.6%	37.6	14.6%	50.5	19.7%	23.5	9.1%
Total OM&A Expenses	810.7	436.8	53.9%	115.8	14.3%	170.9	21.1%	87.2	10.8%

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details DEPRECIATION & DEPLETION EXPENSE 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Assets									
Power Production	259.9	259.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchase Power Agreements (PPA)	48.0	48.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Coal Reserves	3.7	3.7	100.0%	-	0.0%	-	0.0%	-	0.0%
Shand Greenhouse	0.2	0.2	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Assets	311.8	311.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission Assets									
Transmission Assets	81.1	0.1	0.1%	80.1	98.7%	0.9	1.1%	-	0.0%
Total Transmission Assets	81.1	0.1	0.1%	80.1	98.7%	0.9	1.1%	-	0.0%
Distribution Assets									
Distribution Assets	159.8	-	0.0%	-	0.0%	159.8	100.0%	-	0.0%
Meters	6.3	-	0.0%	-	0.0%	6.3	100.0%	-	0.0%
Instrument Transformers	0.9	-	0.0%	-	0.0%	0.9	100.0%	-	0.0%
Total Distribution Assets	167.0	-	0.0%	-	0.0%	167.0	100.0%	-	0.0%
General Plant Assets									
Unused Land	0.0	0.0	53.9%	0.0	14.3%	0.0	21.1%	0.0	10.8%
Right of Use Land	0.8	0.4	53.9%	0.1	14.3%	0.2	21.1%	0.1	10.8%
Buildings	15.6	4.7	29.9%	3.2	20.4%	4.3	27.3%	3.5	22.4%
Right of Use Buildings	2.0	0.6	29.1%	0.4	20.7%	0.5	27.6%	0.4	22.6%
Office Furniture & Equipment	3.6	1.1	29.9%	0.7	20.4%	1.0	27.3%	0.8	22.4%
Vehicles & Equipment	13.4	1.6	12.0%	4.6	34.2%	6.1	45.1%	1.2	8.7%
Computer Development & Equipment	38.2	18.1	47.4%	6.6	17.4%	8.8	23.0%	4.7	12.3%
Communication, Protection & Control	4.8	1.4	28.3%	2.9	60.4%	0.5	10.0%	0.1	1.4%
Tools & Equipment	4.6	1.6	36.0%	1.5	31.8%	1.3	28.7%	0.2	3.5%
Total General Plant Assets	83.1	29.5	35.5%	20.0	24.1%	22.6	27.2%	10.9	13.2%
Total Depreciation Expense	642.9	341.4	53.1%	100.1	15.6%	190.5	29.6%	10.9	1.7%

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details OTHER INCOME 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)							
Expense Categories	SaskPower Total	Functional Breakdown					
		Generation		Transmission		Distribution	
Other Income							
Customer Services Payment Charges	(8.5)	-	0.0%	-	0.0%	-	0.0%
Meter Reading	(2.3)	-	0.0%	-	0.0%	-	0.0%
Transmission	(4.0)	(0.6)	14.2%	(3.5)	85.8%	-	0.0%
Distribution	(7.8)	-	0.0%	-	0.0%	(7.8)	100.0%
Miscellaneous Other Income	(2.1)	(1.1)	53.9%	(0.3)	14.3%	(0.4)	21.1%
Customer Contribution Revenue	(90.2)	-	0.0%	(39.5)	43.8%	(50.7)	56.2%
Green Power Premium	(0.7)	(0.7)	100.0%	-	0.0%	-	0.0%
Flyash Sales	(11.3)	(11.3)	100.0%	-	0.0%	-	0.0%
CO2 Sales & Penalties	(26.6)	(26.6)	100.0%	-	0.0%	-	0.0%
Renewable Energy Credits	(0.8)	(0.8)	100.0%	-	0.0%	-	0.0%
Total Other Income	(154.4)	(41.2)	26.7%	(43.2)	28.0%	(59.0)	38.2%
						(11.0)	7.1%

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalisation and Classification of Financial Account Details																	
GENERATION Related Costs																	
2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)																	
Rate Base and Expense Categories		SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load Demand	Load Energy	Losses Demand	Losses Energy	Scheduling & Dispatch Demand	Regulation & Frequency Response Demand	Spinning Reserve Demand	Supplementary Reserve Demand	Planning Reserve Demand	Reactive Supply Demand	Grants in Lieu of Taxes Energy	
Rate Base																	
Plant in Service (Schedule 2.01)		10,021.2	9,440.6	49.0%	Functional Class of PIS	1,603.5	6,022.5	169.8	496.5	43.0	75.0	207.8	311.7	348.6	162.1	207.8	-
Accumulated Depreciation (Schedule 2.02)		(8,725.3)	(5,201.8)	59.6%	Functional Class of Accum. Dep'n	(971.9)	(3,330.6)	(101.5)	(274.0)	(32.3)	(38.8)	(194.8)	(139.2)	(135.7)	(74.8)	(74.8)	-
Inventories (Schedule 2.03)		361.7	143.3	39.6%	Functional Class of Inventories	63.5	57.8	6.8	4.8	(0.0)	0.5	1.9	2.9	3.2	1.9	4.3	-
Other Assets (Schedule 2.03)		146.2	92.4	63.2%	Functional Classification of Other Assets	31.6	46.7	3.3	3.8	1.8	0.4	0.9	1.4	1.6	0.9	0.9	-
Total Rate Base		10,492.6	4,594.4	41.0%		753.1	2,827.9	79.2	232.7	14.0	37.5	110.7	178.1	199.1	91.7	110.7	4.3
Revenue Requirement																	
Purchased Power & Import		583.1	583.1	100.0%	Functional Class of Fuel Exp.	-	538.5	-	44.5	-	-	-	-	-	-	0.1	-
Export & Net Electricity Trading Revenue (Credit)		(128.9)	(128.9)	100.0%	Functional Class of PP, Import & NP Fee	135.4	(119.0)	-	18.2	-	-	-	-	-	-	0.0	-
Operating, Maintenance & Administration (Schedule 2.04)		810.7	436.8	53.9%	Functional Class of OM&A	-	148.4	-	11.8	12.7	2.8	6.2	9.2	10.3	6.0	6.0	-
Depreciation & Depletion (Schedule 2.05)		642.9	341.4	53.1%	Functional Class of Dep'n & Depletion	208.8	208.8	7.0	17.2	1.1	2.6	7.8	11.7	13.0	2.0	13.0	-
Corporate Capital Tax		57.1	23.5	41.2%	Functional Class of Corp. Capital Tax	3.5	15.0	0.4	1.2	0.1	0.2	0.6	1.0	1.1	0.5	0.5	-
Grants in Lieu of Taxes		34.0	34.0	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax		0.8	0.8	96.8%	Functional Class of Misc. Tax	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
Other Income (Credit) (Schedule 2.06)		(134.4)	(41.2)	26.7%	Functional Class of Other Income	(0.5)	(86.8)	(0.1)	(3.0)	(0.6)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Return on Rate Base @ 5.70%		622.3	258.7	41.6%	Rate Base	42.9	163.3	4.5	13.3	0.8	0.8	2.1	3.0	3.4	5.2	5.2	0.2
Total Revenue Requirement		2,850.1	1,896.6	66.4%		605.8	1,136.7	47.9	93.3	14.0	7.7	21.3	32.0	35.8	17.8	21.3	0.2

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Function Allocation and Classification of Financial Account Details																		
GENERATION PLANT IN SERVICE																		
2024 Fiscal Base Embedded Cost of Service Study																		
(\$ Millions)																		
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes				
				Demand	Energy										Demand	Energy	Demand	Energy
Generation Assets																		
Power Production	7,907.0	7,907.0	100.0%	935.4	5,477.4	99.9	452.6	-	50.9	179.9	269.8	301.7	139.5	-				
Power Production - PPA	1,017.1	1,017.1	100.0%	487.4	329.3	52.1	27.2	-	6.6	23.1	34.7	38.8	17.9	-				
Coal Reserves	-	-	100.0%	-	66.8	-	5.5	-	-	-	-	-	0.0	-				
Shed Greenhouse	6.0	6.0	100.0%	0.8	-	0.1	0.4	-	-	-	-	-	-	-				
Total Generation Assets	9,002.5	9,002.5	100.0%	1,423.6	5,878.3	152.0	485.7	-	57.5	203.0	304.5	340.5	157.4	-				
Transmission Assets																		
Transmission Assets	3,290.6	6.7	0.2%	6.1	-	0.7	-	-	-	-	-	-	-	-				
Total Transmission Assets	3,290.6	6.7	0.2%	6.1	-	0.7	-	-	-	-	-	-	-	-				
Distribution Assets																		
Distribution Assets	5,250.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-				
Meters	117.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-				
Instrument Transformers	20.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-				
Total Distribution Assets	5,388.4	-	-	-	-	-	-	-	-	-	-	-	-	-				
General Plant Assets																		
Unused Land	2.3	1.3	53.9%	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-				
Right of Use Land	9.1	4.9	53.9%	2.3	1.7	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-				
Buildings	638.5	201.7	31.6%	87.0	85.8	8.2	6.3	0.1	0.8	2.3	3.5	3.9	2.3	-				
Right of Use Buildings	2.0	2.0	29.1%	0.9	0.9	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	-				
Office Furniture & Equipment	55.7	32.8	31.6%	7.6	7.5	0.7	0.5	0.1	0.1	0.2	0.3	0.3	0.2	-				
Vehicles & Equipment	225.2	33.3	15.1%	17.1	10.9	1.8	0.9	0.1	0.5	0.5	0.7	0.8	0.5	-				
Computer Development & Equipment	197.8	106.6	53.9%	54.8	34.9	5.7	2.8	(0.4)	0.5	1.6	2.4	2.7	1.6	-				
Communication Protection & Control	184.1	57.2	31.1%	-	-	-	-	-	15.9	-	-	-	-	-				
Tools & Equipment	24.0	6.9	28.6%	3.5	2.2	0.4	0.2	41.3	0.0	0.1	0.2	0.2	0.1	-				
Total General Plant Assets	1,339.8	431.4	32.2%	173.8	144.2	17.1	10.8	-	17.5	4.8	7.3	8.1	4.7	-				
Total Plant in Service	19,021.2	9,440.6	49.6%	1,603.5	6,022.5	169.8	496.5	43.0	75.0	207.8	311.7	346.6	162.1	-				

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details GENERATION ACCUMULATED DEPRECIATION 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)												
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch		Regulation & Frequency Response		Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	
Generation Assets												
Power Production	(4,345.5)	(4,345.5)	100.0%	(604.7)	(3,009.8)	(64.6)	(248.7)	-	(79.5)	(119.3)	(133.4)	-
Power Production - PPA	(611.1)	(611.1)	100.0%	(291.9)	(211.9)	(31.2)	(17.5)	-	(11.2)	(16.8)	(18.8)	(8.8)
Coal Reserves	(47.1)	(47.1)	100.0%	-	(43.5)	-	(3.6)	-	-	-	-	-
Shard Greenhouse	(4.1)	(4.1)	100.0%	(0.6)	(3.2)	(0.1)	(0.3)	-	-	-	-	-
Total Generation Assets	(5,007.8)	(5,007.8)	100.0%	(897.2)	(3,268.3)	(95.8)	(270.0)	-	(90.7)	(136.0)	(152.1)	(71.9)
Transmission Assets												
Transmission Assets	(1,006.1)	(1.6)	0.2%	(1.4)	-	(0.2)	-	-	-	-	-	-
Total Transmission Assets	(1,006.1)	(1.6)	0.2%	(1.4)	-	(0.2)	-	-	-	-	-	-
Distribution Assets												
Distribution Assets	(2,063.6)	-	0.0%	-	-	-	-	-	-	-	-	-
Wetters	(79.3)	-	0.0%	-	-	-	-	-	-	-	-	-
Instrument Transformers	(15.2)	-	0.0%	-	-	-	-	-	-	-	-	-
Total Distribution Assets	(2,158.7)	-	0.0%	-	-	-	-	-	-	-	-	-
General Plant Assets												
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-
Right of Use Land	(3.4)	(1.8)	53.9%	(0.9)	(0.6)	(0.1)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)
Buildings	(70.3)	(25.5)	36.2%	(11.4)	(10.3)	(1.1)	(0.8)	(0.2)	(0.3)	(0.5)	(0.5)	(0.3)
Right of Use Buildings	(4.6)	(1.3)	29.1%	(0.6)	(0.6)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Office Furniture & Equipment	(26.3)	(9.5)	36.2%	(4.3)	(3.8)	(0.4)	(0.3)	(0.1)	(0.1)	(0.2)	(0.2)	(0.1)
Vehicles & Equipment	(130.5)	(18.1)	13.9%	(9.3)	(5.9)	(1.0)	(0.5)	(0.0)	(0.3)	(0.4)	(0.5)	(0.3)
Computer Development & Equipment	(168.4)	(88.2)	52.4%	(45.2)	(29.0)	(4.7)	(2.3)	0.2	(0.4)	(2.0)	(2.2)	(1.3)
Communication, Protection & Control	(141.3)	(44.6)	31.6%	-	-	-	-	-	-	-	-	-
Tools & Equipment	(11.9)	(3.3)	28.0%	(1.7)	(1.1)	(0.2)	-	(32.2)	(12.4)	(0.1)	(0.1)	(0.1)
Total General Plant Assets	(556.7)	(192.3)	34.6%	(73.3)	(51.3)	(7.9)	(4.0)	(32.3)	(13.1)	(3.2)	(3.5)	(2.1)
Total Accumulated Depreciation	(8,729.3)	(5,201.8)	59.6%	(971.9)	(3,319.6)	(103.5)	(274.0)	(32.3)	(38.8)	(199.2)	(155.7)	(74.0)

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details																		
GENERATION INVENTORIES																		
2024 Fiscal Base Embedded Cost of Service Study																		
(\$ Millions)																		
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load Demand	Load Energy	Losses Demand	Losses Energy	Scheduling & Dispatch Demand	Regulation & Frequency Response Demand	Spinning Reserve Demand	Supplementary Reserve Demand	Planning Reserve Demand	Reactive Supply Demand	Grants in Lieu of Taxes				
														Demand	Energy			
Inventories																		
Power Production - Repair Stores	124.9	124.9	100.0%	64.3	40.0	6.9	3.3	-	0.5	1.9	2.9	3.2	1.9	-	-	-		
Power Production - Fuel	19.9	19.9	100.0%	-	18.3	-	1.5	-	-	-	-	-	0.0	-	-	-		
Transmission & Distribution	219.7	219.7	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-		
Miscellaneous (Computers, Power Shop)	(2.88)	(1.15)	53.9%	(0.7)	(0.5)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	-		
Total Inventories	361.7	143.3	39.6%	63.5	57.8	6.8	4.8	(0.0)	0.5	1.9	2.9	3.2	1.9	-	-	-		

Functionalization and Classification of Financial Account Details																		
GENERATION OTHER ASSETS																		
2024 Fiscal Base Embedded Cost of Service Study																		
(\$ Millions)																		
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load Demand	Load Energy	Losses Demand	Losses Energy	Scheduling & Dispatch Demand	Regulation & Frequency Response Demand	Spinning Reserve Demand	Supplementary Reserve Demand	Planning Reserve Demand	Reactive Supply Demand	Grants in Lieu of Taxes				
														Demand	Energy			
Other Assets																		
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	26.3	26.3	100.0%	-	24.3	-	2.0	-	-	-	-	-	0.0	-	-	-		
Intangible Assets	82.2	44.3	53.9%	21.1	15.0	2.2	1.2	1.3	0.3	0.6	0.9	1.0	0.6	-	-	-		
Prepaid Expenses - Insurance	3.8	3.8	90.0%	1.9	1.2	0.2	0.1	-	0.0	0.1	0.1	0.1	0.1	-	-	-		
Miscellaneous Prepaid Expenses	33.5	18.0	53.9%	8.6	6.1	0.9	0.5	0.5	0.1	0.3	0.4	0.4	0.2	-	-	-		
Total Other Assets	146.2	92.4	63.2%	31.5	46.7	3.3	3.8	1.8	0.4	0.9	1.4	1.4	0.9	-	-	-		

Schedule 2.04: Functional Classification of Financial Account Details – Generation OM&A Expenses

Functionalization and Classification of Financial Account Details																		
GENERATION OM&A EXPENSES																		
2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)																		
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve		Planning Reserve		Reactive Supply	Grants in Lieu of Taxes	
				Demand	Energy	Demand	Energy			Demand	Energy	Demand	Energy	Demand	Energy		Demand	Energy
Generation Expenses																		
Power Plant Operation	226.4	226.4	100.0%	116.4	72.5	12.4	6.0	-	1.0	3.5	-	5.3	5.9	-	3.4	-	-	-
Power Production Overhead	30.5	30.5	100.0%	15.7	9.8	1.7	0.8	-	0.1	0.5	-	0.7	0.8	-	0.5	-	-	-
Purchase Power Agreements (PPA)	13.0	13.0	100.0%	4.4	6.5	0.5	0.5	-	0.1	0.2	-	0.3	0.3	-	0.2	-	-	-
Total Generation Expenses	269.9	269.9	100.0%	136.6	88.8	14.6	7.3	-	1.2	4.2	-	6.3	7.0	-	4.1	-	-	-
Transmission & Distribution Expenses																		
Transmission Support	24.3	13.2	54.3%	0.0	0.2	0.0	0.0	12.0	1.0	-	-	-	-	-	-	-	-	-
Distribution	67.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission including 230/138 & 72 kV Radials	120.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Services	8.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Metering Services	5.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	226.3	13.2	5.8%	0.0	0.2	0.0	0.0	12.0	1.0	-	-	-	-	-	-	-	-	-
Customer Services Expenses																		
Meter Reading	11.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	1.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	8.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	2.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	8.3	8.3	100.0%	4.2	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	21.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	57.5	8.3	14.5%	4.2	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Support Group Expenses																		
President / Board	2.2	1.2	53.9%	0.6	0.4	0.1	0.0	0.0	0.0	0.0	-	0.0	0.0	-	0.0	-	-	-
Corporate & Financial Services (C&FS)	11.3	5.0	44.0%	2.3	1.9	0.2	0.1	0.0	0.0	0.0	-	0.0	0.1	-	0.1	-	-	-
C&FS - Insurance Premiums & Insurable Losses	19.2	17.3	90.0%	8.9	5.5	1.0	0.5	-	0.1	0.3	-	0.4	0.4	-	0.3	-	-	-
Asset Management, Planning, & Sustainability	22.8	22.8	100.0%	12.3	7.7	1.3	0.6	0.0	0.0	0.1	-	0.1	0.1	-	0.1	-	-	-
Integrated Carbon Capture & Sequestration	0.1	0.1	100.0%	0.1	0.0	0.0	0.0	-	0.0	0.0	-	0.0	0.0	-	0.0	-	-	-
SMR Consortium	7.3	4.0	53.9%	1.9	1.3	0.2	0.1	-	0.0	0.0	-	0.0	0.0	-	0.0	-	-	-
General Council / Land	0.1	0.1	100.0%	0.1	0.0	0.0	0.0	-	0.0	0.0	-	0.0	0.0	-	0.0	-	-	-
Safety	6.8	3.3	48.4%	1.6	1.1	0.2	0.1	0.1	0.0	0.0	-	0.1	0.1	-	0.1	-	-	-
Corporate Information & Technology	102.6	48.2	47.0%	23.9	16.6	2.5	1.3	0.1	0.0	0.1	-	0.1	0.1	-	0.1	-	-	-
Human Resources	32.3	12.5	38.7%	5.9	4.5	0.6	0.4	0.2	0.1	0.2	-	0.3	0.3	-	0.2	-	-	-
Commercial & Industrial Operations	11.5	11.5	100.0%	2.1	8.2	0.2	0.7	0.1	0.1	0.1	-	0.1	0.1	-	0.1	-	-	-
Information Systems	26.8	11.8	44.0%	5.5	4.5	0.6	0.4	0.1	0.0	0.2	-	0.2	0.2	-	0.1	-	-	-
Total Support Group Expenses	257.0	145.3	56.6%	67.0	55.3	7.0	4.5	11.8	2.8	6.2	-	3.0	3.3	-	1.9	-	-	-
Total OM&A Expenses	810.7	436.8	53.9%	207.8	148.4	21.6	11.8	12.7	2.8	9.2	-	10.3	10.3	-	6.0	-	-	-

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details GENERATION DEPRECIATION & DEPLETION 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)																
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy			Demand	Energy	Demand	Energy			
Generation Assets																
Power Production	259.9	259.9	100.0%	29.4	180.0	3.1	14.9	-	1.8	6.2	9.3	10.5	4.7	-	-	-
Purchase Power Agreements (PPA)	48.0	48.0	100.0%	23.2	13.1	2.5	1.7	-	0.3	1.2	1.7	1.9	0.9	-	-	-
Coal Reserves	3.7	3.7	100.0%	0.0	3.4	0.0	0.0	-	-	-	-	-	-	-	-	-
Shard Generating House	0.2	0.2	100.0%	0.0	0.1	0.0	0.0	-	-	-	-	-	-	-	-	-
Total Generation Assets	311.8	311.8	100.0%	52.6	196.7	5.6	16.4	-	2.1	7.4	11.1	12.4	5.6	-	-	-
Transmission Assets																
Transmission Assets	81.1	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	81.1	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-	-	-
Distribution Assets																
Distribution Assets	159.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters	6.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Instrument Transformers	0.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	167.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant Assets																
Unused Land	0.0	0.0	53.9%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Right of Use Land	0.8	0.4	53.9%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Buildings	15.6	4.7	29.9%	2.0	2.0	0.2	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-	-	-
Right of Use Buildings	2.0	0.6	29.1%	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Office Furniture & Equipment	3.6	1.1	29.9%	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Vehicles & Equipment	13.4	1.6	12.0%	0.8	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Computer Development & Equipment	38.2	18.1	47.4%	9.0	6.2	0.9	0.5	0.0	0.4	0.3	0.4	0.4	0.3	-	-	-
Communication, Protection & Control	4.8	1.4	28.3%	-	-	-	-	-	1.0	-	-	-	-	-	-	-
Tools & Equipment	4.6	1.6	36.0%	0.8	0.5	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-	-	-
Total General Plant Assets	83.1	29.5	35.5%	13.6	10.2	1.4	0.8	1.1	0.5	0.4	0.6	0.7	0.4	-	-	-
Total Depreciation & Depletion	642.9	341.4	53.1%	66.3	208.8	7.0	17.2	1.1	2.6	7.8	11.7	13.0	6.0	-	-	-

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details														
GENERATION OTHER INCOME														
2024 Fiscal Base Embedded Cost of Service Study														
(\$ millions)														
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy							
Other Income														
Customer Services Payment Charges	(8.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission	(4.0)	(0.6)	14.2%	-	-	-	-	(0.5)	(0.0)	-	-	-	-	-
Distribution	(7.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Other Income	(2.1)	(1.1)	53.9%	(0.5)	(0.4)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Customer Contributions Revenue	(90.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Green Power Premium	(0.7)	(0.7)	100.0%	-	(0.6)	-	(0.1)	-	-	-	-	-	-	-
Flyash Sales	(11.3)	(11.3)	100.0%	-	(10.4)	-	(0.9)	-	-	-	-	-	-	-
CO2 Sales & Penalties	(26.6)	(26.6)	100.0%	-	(24.6)	-	(2.0)	-	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	(0.8)	100.0%	-	(0.8)	-	(0.1)	-	-	-	-	-	-	-
Total Other Income	(154.4)	(41.2)	26.7%	(0.5)	(36.8)	(0.1)	(3.0)	(0.6)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details								
TRANSMISSION Related Costs								
2024 Fiscal Base Embedded Cost of Service Study								
(\$ Millions)								
Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid	230kV & 138kV Radials	138/72 kV Substations	72 kV Lines Radials
					Demand	Demand	Demand	Demand
Rate Base								
Plant in Service (Schedule 2.11)	19,021.2	3,606.5	19.0%	Functional Class of P/S	2,217.9	828.8	181.4	378.4
Accumulated Depreciation (Schedule 2.12)	(8,729.3)	(1,159.2)	13.3%	Functional Class of Accum. Depr'n	(693.1)	(290.8)	(70.3)	(105.0)
Allowance For Working Capital	112.8	16.2	14.3%	12.50% of OM&A and Taxes	9.9	3.6	1.2	1.5
Inventories (Schedule 2.13)	361.7	86.1	23.8%	Functional Class of Inventories	52.4	19.2	6.9	7.7
Other Assets (Schedule 2.13)	146.2	16.7	11.4%	Functional Classification of Other Assets	10.1	3.7	1.3	1.5
Total Rate Base	10,912.6	2,566.3	23.5%		1,597.1	564.5	120.5	284.1
Revenue Requirement								
Fuel Expense SaskPower Units	583.1	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-
Purchased Power & Import	388.3	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(128.9)	-	0.0%	Functional Class of Exports	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.14)	810.7	115.8	14.3%	Functional Class of OM&A	70.4	25.8	9.2	10.3
Depreciation & Depletion (Schedule 2.15)	642.9	100.1	15.6%	Functional Class of Dep'n & Depletion	60.4	24.5	4.7	10.5
Corporate Capital Tax	57.1	13.6	23.8%	Functional Class of Corp. Capital Tax	8.5	3.0	0.6	1.5
Grants in Lieu of Taxes	34.0	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-
Miscellaneous Tax	0.8	0.0	1.0%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.16)	(154.4)	(43.2)	28.0%	Functional Class of Other Income	(2.4)	(40.2)	(0.3)	(0.3)
Return on Rate Base @ 5.70%	622.3	146.3	23.5%	Rate Base	91.1	32.2	6.9	16.2
Total Revenue Requirement	2,856.1	332.6	11.6%		227.9	45.3	21.1	38.2

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details TRANSMISSION PLANT IN SERVICE 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Generation Assets											
Power Production	7,907.0	-	0.0%	-	-	-	-	-	-	-	-
Power Production - PPA	1,017.1	-	0.0%	-	-	-	-	-	-	-	-
Coal Reserves	72.4	-	0.0%	-	-	-	-	-	-	-	-
Shand Greenhouse	6.0	-	0.0%	-	-	-	-	-	-	-	-
Total Generation Assets	9,002.5	-	0.0%	-	-	-	-	-	-	-	-
Transmission Assets											
Transmission Assets	3,290.6	3,250.8	98.8%	2,001.6	2,001.6	749.5	749.5	153.0	153.0	346.7	346.7
Total Transmission Assets	3,290.6	3,250.8	98.8%								
Distribution Assets											
Distribution Assets	5,250.7	-	0.0%	-	-	-	-	-	-	-	-
Meters	117.4	-	0.0%	-	-	-	-	-	-	-	-
Instrument Transformers	20.3	-	0.0%	-	-	-	-	-	-	-	-
Total Distribution Assets	5,388.4	-	0.0%	-	-	-	-	-	-	-	-
General Plant Assets											
Unused Land	2.3	0.3	14.3%	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0
Right of Use Land	9.1	1.3	14.3%	0.8	0.8	0.3	0.3	0.1	0.1	0.1	0.1
Buildings	638.5	126.9	19.9%	77.2	77.2	28.3	28.3	10.1	10.1	11.3	11.3
Right of Use Buildings	7.0	1.4	20.7%	0.9	0.9	0.3	0.3	0.1	0.1	0.1	0.1
Office Furniture & Equipment	55.7	11.1	19.9%	6.7	6.7	2.5	2.5	0.9	0.9	1.0	1.0
Vehicles & Equipment	221.2	73.5	33.2%	44.7	44.7	16.4	16.4	5.9	5.9	6.5	6.5
Computer Development & Equipment	197.8	29.9	15.1%	18.2	18.2	6.7	6.7	2.4	2.4	2.7	2.7
Communication, Protection & Control	184.1	103.1	56.0%	62.7	62.7	23.0	23.0	8.2	8.2	9.2	9.2
Tools & Equipment	24.0	8.2	34.0%	5.0	5.0	1.8	1.8	0.7	0.7	0.7	0.7
Total General Plant Assets	1,339.8	355.7	26.6%	216.3	216.3	79.3	79.3	28.4	28.4	31.7	31.7
Total Plant in Service	19,021.2	3,606.5	19.0%	2,217.9	2,217.9	828.8	828.8	181.4	181.4	378.4	378.4

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details TRANSMISSION ACCUMULATED DEPRECIATION 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials				
				Demand	Demand	Demand	Demand				
Generation Assets											
Power Production	(4,345.5)	-	0.0%	-	-	-	-				
Power Production - PPA	(611.1)	-	0.0%	-	-	-	-				
Coal Reserves	(47.1)	-	0.0%	-	-	-	-				
Shand Greenhouse	(4.1)	-	0.0%	-	-	-	-				
Total Generation Assets	(5,007.8)	-	0.0%	-	-	-	-				
Transmission Assets											
Transmission Assets	(1,006.1)	(987.2)	98.1%	(588.6)	(252.5)	(56.5)	(89.7)				
Total Transmission Assets	(1,006.1)	(987.2)	98.1%	(588.6)	(252.5)	(56.5)	(89.7)				
Distribution Assets											
Distribution Assets	(2,063.6)	-	0.0%	-	-	-	-				
Meters	(79.9)	-	0.0%	-	-	-	-				
Instrument Transformers	(15.2)	-	0.0%	-	-	-	-				
Total Distribution Assets	(2,158.7)	-	0.0%	-	-	-	-				
General Plant Assets											
Unused Land	-	-	0.0%	-	-	-	-				
Right of Use Land	(3.4)	(0.5)	14.3%	(0.3)	(0.1)	(0.0)	(0.0)				
Buildings	(70.3)	(13.1)	18.6%	(8.0)	(2.9)	(1.0)	(1.2)				
Right of Use Buildings	(4.6)	(0.9)	20.7%	(0.6)	(0.2)	(0.1)	(0.1)				
Office Furniture & Equipment	(26.3)	(4.9)	18.6%	(3.0)	(1.1)	(0.4)	(0.4)				
Vehicles & Equipment	(130.5)	(44.0)	33.7%	(26.7)	(9.8)	(3.5)	(3.9)				
Computer Development & Equipment	(168.4)	(26.4)	15.7%	(16.1)	(5.9)	(2.1)	(2.4)				
Communication, Protection & Control	(141.3)	(77.7)	55.0%	(47.2)	(17.3)	(6.2)	(6.9)				
Tools & Equipment	(11.9)	(4.5)	37.7%	(2.7)	(1.0)	(0.4)	(0.4)				
Total General Plant Assets	(556.7)	(172.0)	30.9%	(104.6)	(38.4)	(13.7)	(15.3)				
Total Accumulated Depreciation	(8,729.3)	(1,159.2)	13.3%	(693.1)	(290.8)	(70.3)	(105.0)				

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details											
TRANSMISSION INVENTORIES											
2024 Fiscal Base Embedded Cost of Service Study											
(\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Inventories											
Power Production - Repair Stores	124.9	-	0.0%	-	-	-	-	-	-	-	-
Power Production - Fuel	19.9	-	0.0%	-	-	-	-	-	-	-	-
Transmission & Distribution	219.7	86.5	39.4%	52.6	19.3	6.9	7.7				
Miscellaneous (Computers, Power Shop)	(2.8)	(0.4)	14.3%	(0.2)	(0.1)	(0.0)	(0.0)				
Total Inventories	361.7	86.1	23.8%	52.4	19.2	6.9	7.7				

Functionalization and Classification of Financial Account Details											
TRANSMISSION OTHER ASSETS											
2024 Fiscal Base Embedded Cost of Service Study											
(\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Other Assets											
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	26.3	-	0.0%	-	-	-	-	-	-	-	-
Intangible Assets	82.2	11.7	14.3%	7.1	2.6	0.9	1.0	0.9	1.0	0.9	1.0
Prepaid Expenses - Insurance	4.2	0.2	4.0%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	33.5	4.8	14.3%	2.9	1.1	0.4	1.1	0.4	0.4	0.4	0.4
Total Other Assets	146.2	16.7	11.4%	10.1	3.7	1.3	1.5	1.3	1.3	1.3	1.5

Schedule 2.14: Functional Classification of Financial Account Details – Transmission OM&A Expenses

Functionalization and Classification of Financial Account Details											
TRANSMISSION OM&A EXPENSE											
2024 Fiscal Base Embedded Cost of Service Study											
(\$ Millions)											
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials				
					Demand	Demand	Demand				
Generation Expenses											
Power Plant Operation	226.4	-	0.0%	-	-	-	-				
Power Production Overhead	30.5	-	0.0%	-	-	-	-				
Purchase Power Agreements (PPA)	13.0	-	0.0%	-	-	-	-				
Total Generation Expenses	269.9	-	0.0%	-	-	-	-				
Transmission & Distribution Expenses											
Planning Support	24.3	10.7	44.2%	6.6	2.5	0.5	1.1				
Transmission Including 230/138 & 72 kV Radials	67.4	67.4	100.0%	40.9	15.0	5.7	5.8				
Distribution	120.2	-	0.0%	-	-	-	-				
Customer Services	8.8	-	0.0%	-	-	-	-				
Metering Services	5.6	-	0.0%	-	-	-	-				
Total Transmission & Distribution Expenses	226.3	78.2	34.5%	47.5	17.4	6.2	7.0				
Customer Services Expenses											
Meter Reading	11.9	-	0.0%	-	-	-	-				
Billing Services	3.2	-	0.0%	-	-	-	-				
Collections/Special Collections	1.6	-	0.0%	-	-	-	-				
Bad Debt Expense	8.3	-	0.0%	-	-	-	-				
Marketing & Sales	2.6	-	0.0%	-	-	-	-				
Demand Side Management	8.3	-	0.0%	-	-	-	-				
Customer Service	21.5	-	0.0%	-	-	-	-				
Total Customer Services Expenses	57.5	-	0.0%	-	-	-	-				
Support Group Expenses											
President / Board	2.2	0.3	14.3%	0.2	0.1	0.0	0.0				
Corporate & Financial Services (C&FS)	11.3	2.1	18.6%	1.3	0.5	0.2	0.2				
C&FS - Insurance Premiums & Insurable Losses	19.2	0.8	4.0%	0.5	0.2	0.1	0.1				
Asset Management, Planning, & Sustainability	12.8	2.3	18.3%	1.4	0.5	0.2	0.2				
Integrated Carbon Capture & Sequestration	23.9	-	0.0%	-	-	-	-				
SMR Consortium	0.1	-	0.0%	-	-	-	-				
General Council / Land	7.3	1.0	14.3%	0.6	0.2	0.1	0.1				
Safety	6.8	1.2	17.5%	0.7	0.3	0.1	0.1				
Corporate Information & Technology	102.6	17.9	17.4%	10.9	4.0	1.4	1.6				
Human Resources	32.3	6.9	21.4%	4.2	1.5	0.6	0.6				
Commercial & Industrial Operations	11.5	-	0.0%	-	-	-	-				
Procurement & Supply Chain	26.8	5.0	18.6%	3.0	1.1	0.4	0.4				
Total Support Group Expenses	257.0	37.6	14.6%	22.9	8.4	3.0	3.3				
Total OM&A Expenses	810.7	115.8	14.3%	70.4	25.8	9.2	10.3				

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details TRANSMISSION DEPRECIATION & DEPLETION 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
				Demand	Demand	Demand	Demand
Generation Assets							
Power Production	259.9	-	0.0%	-	-	-	-
Purchase Power Agreements (PPA)	48.0	-	0.0%	-	-	-	-
Coal Reserves	3.7	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation Assets	311.8	-	0.0%	-	-	-	-
Transmission Assets							
Transmission Assets	81.1	80.1	98.7%	48.2	20.1	3.1	8.7
Total Transmission Assets	81.1	80.1	98.7%	48.2	20.1	3.1	8.7
Distribution Assets							
Distribution Assets	159.8	-	0.0%	-	-	-	-
Meters	6.3	-	0.0%	-	-	-	-
Instrument Transformers	0.9	-	0.0%	-	-	-	-
Total Distribution Assets	167.0	-	0.0%	-	-	-	-
General Plant Assets							
Unused Land	0.0	0.0	14.3%	0.0	0.0	0.0	0.0
Right of Use Land	0.8	0.1	14.3%	0.1	0.0	0.0	0.0
Buildings	15.6	3.2	20.4%	1.9	0.7	0.3	0.3
Right of Use Buildings	2.0	0.4	20.7%	0.2	0.1	0.0	0.0
Office Furniture & Equipment	3.6	0.7	20.4%	0.5	0.2	0.1	0.1
Vehicles & Equipment	13.4	4.6	34.2%	2.8	1.0	0.4	0.4
Computer Development & Equipment	38.2	6.6	17.4%	4.0	1.5	0.5	0.6
Communication, Protection & Control	4.8	2.9	60.4%	1.8	0.7	0.2	0.3
Tools & Equipment	4.6	1.5	31.8%	0.9	0.3	0.1	0.1
Total General Plant Assets	83.1	20.0	24.1%	12.2	4.5	1.6	1.8
Total Depreciation & Depletion	642.9	100.1	15.6%	60.4	24.5	4.7	10.5

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details										
TRANSMISSION OTHER INCOME										
2024 Fiscal Base Embedded Cost of Service Study										
(\$ Millions)										
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials			
				Demand	Demand	Demand	Demand			
Other Income										
Customer Services Payment Charges	(8.5)	-	0.0%	-	-	-	-			
Meter Reading	(2.3)	-	0.0%	-	-	-	-			
Transmission	(4.0)	(3.5)	85.8%	(2.1)	(0.8)	(0.3)	(0.3)			
Distribution	(7.8)	-	0.0%	-	-	-	-			
Miscellaneous Other Income	(2.1)	(0.3)	14.3%	(0.2)	(0.1)	(0.0)	(0.0)			
Customer Contribution Revenue	(90.2)	(39.5)	43.8%	(0.2)	(39.4)	-	0.1			
Green Power Premium	(0.7)	-	0.0%	-	-	-	-			
Flyash Sales & Wind Power	(11.3)	-	0.0%	-	-	-	-			
CO2 Sales & Penalties	(26.6)	-	0.0%	-	-	-	-			
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-			
Total Other Income	(154.4)	(43.2)	28.0%	(2.4)	(40.2)	(0.3)	(0.3)			

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details																		
2024 Fiscal Base Embedded Cost of Service Study																		
DISTRIBUTION Related Costs																		
(\$ Millions)																		
Rate Base	Rate Base and Expense Categories	S&P Power Total	Distribution Total	Distribution as a % of Recovered Total	Basis of Classification	Area Subtotals		Distribution (Units)		Rural Loadings		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streightlights
						Demand	Subtotal	Demand	Urban Loadings	Demand	Customer	Demand	Customer					
Rate Base																		
	Plant in Service (Schedule 2.21)	19,021.2	5,774.5	30.4%	Functional Class of PIS	52.57	1,593.1	171.9	401.2	322.6	752.8	449.9	242.2	1,020.7	20.3	-	117.4	156.6
	Accumulated Depreciation (Schedule 2.22)	(8,729.3)	(2,214.5)	26.5%	Functional Class of Accum. Depn	(201.6)	(6,596)	(80.5)	(187.9)	(149.7)	(340.2)	(150.2)	(89.9)	(302.3)	(15.2)	-	(79.9)	(95.6)
	Depreciation of Capital Assets (Schedule 2.23)	363.7	132.6	36.7%	Functional Class of Inventories	12.0	37.8	5.7	33.3	10.7	24.9	12.9	7.3	2.2	0.0	-	0.0	4.0
	Other Assets (Schedule 2.23)	146.2	24.6	16.8%	Functional Classification of Other Assets	2.2	7.0	1.1	2.5	2.0	4.6	1.1	1.3	0.4	-	-	-	6.0
	Total Rate Base	19,017.6	3,641.0	31.4%		316.6	955.1	95.1	233.3	187.5	417.5	317.3	170.8	722.0	5.1	-	109.1	371.1
Rate Base Recovery																		
Rate Base Recovery Units																		
	Purchased Power & Import	583.1	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-
	Export & Net Electricity Trading Revenue (Credit)	(128.9)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation of Capital Assets (Schedule 2.24)	1,709.0	170.9	7.3%	Functional Class of Depn & Depreciation	15.6	46.7	7.3	17.4	13.6	35.2	16.6	9.0	2.9	-	-	7.7	10.7
	Depreciation & Depreciation (Schedule 2.25)	190.5	190.5	29.6%	Functional Class of Depn & Depreciation	16.7	46.7	5.9	33.8	11.0	25.7	16.7	30.0	0.9	-	-	6.6	9.2
	Corporate Capital Tax	671.9	57.1	19.2	Functional Class of Corp. Capital Tax	1.8	5.2	1.0	1.2	1.0	2.2	1.7	0.9	4.0	0.0	-	0.3	6.3
	Grants in Lieu of Taxes	34.0	0.0	0.0%	Functional Class of Grants in Lieu of Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-
	Other Income (Credit) (Schedule 2.26)	(154.6)	(59.0)	-	Functional Classification of Other Income	(0.8)	(4.2)	(1.1)	(2.9)	(2.9)	(6.7)	(0.8)	(0.4)	(37.2)	-	-	(2.6)	(6.6)
	Return on Rate Base @ 5.70%	627.3	207.6	38.2%	Rate Base	19.3	56.2	5.7	13.2	10.7	26.9	18.1	28.2	41.2	0.3	-	2.1	26.1
	Total Revenue Requirement	2,854.1	529.2	18.5%		53.7	152.6	18.4	42.9	33.4	79.4	52.3	28.2	46.9	1.2	-	8.6	38.5

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details																			
DISTRIBUTION PLANT IN SERVICE																			
2024 Fiscal Base Embedded Cost of Service Study																			
(\$ Millions)																			
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streetlights	
				Demand		Demand		Demand	Customer	Demand	Customer	Demand	Customer						
Generation Assets																			
Power Production	7,907.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Production - PPA	1,017.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Coal Reserves	72.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Shard Greenhouse	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Generation Assets	9,002.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission Assets																			
Transmission Assets	3,290.6	33.1	1.0%	33.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Transmission Assets	3,290.6	33.1	1.0%	33.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution Assets																			
Distribution Assets	5,250.7	5,250.7	100.0%	460.6	-	1,492.4	-	156.8	365.8	294.2	686.4	415.5	223.7	1,014.7	-	-	-	140.6	
Meters	117.4	117.4	100.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	117.4	-	
Instrument Transformers	20.3	20.3	100.0%	-	-	-	-	-	-	-	-	-	-	20.3	-	-	-	-	
Total Distribution Assets	5,388.4	5,388.4	100.0%	460.6	-	1,492.4	-	156.8	365.8	294.2	686.4	415.5	223.7	1,014.7	20.3	-	117.4	140.6	
General Plant Assets																			
Unsettled Land	2.3	0.5	21.1%	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	-	-	-	0.0	
Right of Use Land	9.1	1.9	21.1%	0.0	0.2	0.5	0.2	0.2	0.2	0.4	0.2	0.4	0.2	0.0	-	-	-	0.0	
Buildings	638.5	169.7	26.6%	15.4	48.4	48.4	7.3	17.0	31.9	13.7	31.9	16.5	8.9	2.9	-	-	-	7.7	
Right of Use Buildings	7.0	1.9	27.6%	0.2	0.5	0.5	0.1	0.2	0.4	0.2	0.4	0.2	0.1	0.0	-	-	-	0.1	
Office Furniture & Equipment	55.7	14.8	26.6%	1.3	4.2	4.2	0.6	1.5	1.2	1.2	2.8	1.4	0.8	0.3	-	-	-	0.7	
Vehicles & Equipment	221.2	96.9	43.8%	8.8	27.6	27.6	4.2	9.7	7.8	7.8	18.2	9.4	5.1	1.6	-	-	-	4.4	
Computer Development & Equipment	197.8	38.4	19.4%	3.5	10.9	10.9	1.6	3.8	3.1	3.1	7.2	3.7	2.0	0.7	-	-	-	1.7	
Communication, Protection & Control	184.1	20.9	11.4%	1.9	6.0	6.0	0.9	2.1	1.7	1.7	3.9	2.0	1.1	0.4	-	-	-	0.9	
Tools & Equipment	24.0	8.0	33.2%	0.7	2.3	2.3	0.3	0.8	0.6	0.6	1.5	0.8	0.4	0.1	-	-	-	0.4	
Total General Plant Assets	1,339.8	353.1	26.4%	32.1	100.7	100.7	15.2	35.4	28.5	34.4	66.4	44.9	24.2	6.0	-	-	-	16.0	
Total Plant in Service	19,021.2	5,774.5	30.4%	525.7	1,593.1	1,593.1	171.9	401.2	322.6	322.6	752.8	449.9	242.2	1,020.7	20.3	-	117.4	156.6	

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details																			
DISTRIBUTION ACCUMULATED DEPRECIATION																			
2024 Fiscal Base Embedded Cost of Service Study																			
(\$ Millions)																			
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains	Urban Laterals	Rural Laterals	Transformers	Transformers	Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streetlights					
				Demand	Demand	Demand	Demand	Demand	Customer	Customer	Customer	Customer	Customer	Customer					
Generation Assets																			
Power Production - PPA	(4,345.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Power Production - Coal	(611.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Coal Reserves	(47.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Shed Greenhouse	(4.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Total Generation Assets	(5,007.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Transmission Assets																			
Transmission Assets	(1,006.1)	(17.2)	1.7%	(17.2)	-	-	-	-	-	-	-	-	-	-					
Total Transmission Assets	(1,006.1)	(17.2)	1.7%	(17.2)	-	-	-	-	-	-	-	-	-	-					
Distribution Assets																			
Distribution Assets	(2,063.6)	(2,063.6)	100.0%	(173.8)	(620.1)	(74.6)	(138.5)	(323.1)	(136.7)	(73.6)	(299.9)	-	-	(49.3)					
Meters	(79.9)	(79.9)	100.0%	-	-	-	-	-	-	-	-	-	-	(79.9)					
Instrument Transformers	(15.2)	(15.2)	100.0%	-	-	-	-	-	-	-	-	(15.2)	-	-					
Total Distribution Assets	(2,158.7)	(2,158.7)	100.0%	(173.8)	(620.1)	(74.6)	(138.5)	(323.1)	(136.7)	(73.6)	(299.9)	-	-	(49.3)					
General Plant Assets																			
Unsewered Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Right of Use Land	(3.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-					
Buildings	(70.3)	(17.5)	24.9%	(0.1)	(1.6)	(0.8)	(1.4)	(3.3)	(1.7)	(0.9)	(0.3)	-	-	(0.0)					
Office of Use Buildings	(4.6)	(1.3)	1.3%	(0.1)	(0.4)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.0)	-	-	(0.0)					
Office Furniture & Equipment	(26.3)	(6.5)	27.6%	(0.1)	(0.6)	(0.3)	(0.5)	(1.2)	(0.6)	(0.3)	(0.1)	-	-	(0.1)					
Vehicle & Equipment	(130.5)	(58.0)	44.4%	(5.3)	(16.5)	(2.5)	(5.8)	(13.9)	(5.6)	(3.0)	(1.0)	-	-	(0.6)					
Computer Development & Equipment	(168.4)	(34.2)	20.3%	(3.1)	(9.7)	(1.5)	(3.4)	(6.4)	(3.3)	(1.8)	(0.9)	-	-	(0.3)					
Communication, Protection & Control	(141.3)	(16.7)	11.8%	(1.5)	(4.8)	(0.7)	(1.7)	(3.1)	(1.6)	(0.9)	(0.3)	-	-	(0.1)					
Tools & Equipment	(11.9)	(3.6)	30.5%	(0.3)	(1.0)	(0.2)	(0.4)	(0.7)	(0.4)	(0.2)	(0.1)	-	-	(0.2)					
Total General Plant Assets	(566.2)	(138.5)	24.9%	(39.3)	(126)	(60.2)	(13.9)	(26.1)	(13.5)	(2.3)	(2.3)	-	-	(6.3)					
Total Accumulated Depreciation	(8,729.3)	(2,314.5)	26.5%	(203.6)	(659.6)	(80.5)	(187.9)	(349.2)	(150.2)	(80.9)	(302.3)	-	-	(79.9)					

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details																
DISTRIBUTION INVENTORIES																
2024 Fiscal Base Embedded Cost of Service Study																
(\$ Millions)																
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Rural Laterals		Streetlights
				Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total	
Inventories																
Power Production - Repair Stores	124.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Distribution	219.7	133.2	60.6%	12.1	38.0	5.7	13.4	10.7	25.1	13.0	7.0	2.3	6.0	0.0	0.0	6.0
Transmission & Distribution	(2.8)	(0.6)	21.1%	(0.1)	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous (Computers, Power Shop)																
Total Inventories	361.7	132.6	36.7%	12.0	37.8	5.7	13.3	10.7	24.9	12.9	7.0	2.2	6.0			

Functionalization and Classification of Financial Account Details																
DISTRIBUTION OTHER ASSETS																
2024 Fiscal Base Embedded Cost of Service Study																
(\$ Millions)																
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Rural Laterals		Streetlights
				Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total	
Other Assets																
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	26.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	82.2	17.3	21.1%	1.6	4.9	0.7	1.7	1.4	3.3	1.7	0.9	0.3	0.8	0.0	0.0	0.8
Prepaid Expenses - Insurance	4.2	0.2	5.3%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Prepaid Expenses - Power Shop	35.2	35.2	100.0%	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Total Other Assets	148.2	24.6	16.8%	2.2	7.0	2.9	3.3	2.6	4.2	2.4	1.3	0.4	1.3			

Schedule 2.24: Functional Classification of Financial Account Details – Distribution OM&A Expenses

Functionalization and Classification of Financial Account Details														
DISTRIBUTION OM&A EXPENSES														
2024 Fiscal Base Embedded Cost of Service Study														
(\$ Millions)														
Expense Categories	SaskPower Total	Distribution Total	Distribution % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers Demand		Streetlights Customer
				Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total	
Generation Expenses														
Power Plant Operation	206.4	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Power Plant Maintenance	12.4	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	13.0	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Total Generation Expenses	209.9	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Transmission & Distribution Expenses														
Planning Support	24.3	0.1	0.4%	0.0	0.1	-	-	-	-	-	-	-	-	-
Transmission including 230/138 & 72 kV Radials	67.4	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Distribution	120.2	120.2	100.0%	10.9	34.2	5.2	12.1	9.7	22.6	11.7	6.3	2.0	2.0	5.4
Substation Services	1.0	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Material Services	5.6	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	226.3	120.3	53.2%	10.9	34.3	5.2	12.1	9.7	22.6	11.7	6.3	2.0	2.0	5.4
Customer Services Expenses														
Meter Reading	11.9	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Billing Services	3.2	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Collections/Special Collections	1.6	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Marketing Services	1.6	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Marketing & Sales	2.6	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Demand Side Management	8.3	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Customer Service	21.5	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	57.5	-	-	-	0.0%	-	-	-	-	-	-	-	-	-
Support Group Expenses														
President / Board	2.2	0.5	2.11%	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Finance & Financial Services (C&F)	1.1	0.6	2.55%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customer Service & Communications	19.2	1.1	24.53%	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Asset Management, Planning, & Sustainability	12.8	3.1	24.53%	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Integrated Carbon Capture & Sequestration	23.9	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR Consortium	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-
General Council / Land	7.3	1.5	21.1%	0.1	0.4	0.4	0.2	0.1	0.3	0.2	0.1	0.0	0.0	-
Safety	6.8	1.7	24.33%	0.2	0.5	0.5	0.2	0.1	0.3	0.2	0.1	0.0	0.0	-
Regulatory Information & Technology	36.1	2.3	24.33%	0.4	1.1	1.1	0.4	0.1	0.5	0.4	0.1	0.0	0.0	-
Human Resources	32.3	9.4	29.2%	0.9	2.7	2.7	0.9	0.8	1.8	0.9	0.5	0.2	0.2	0.4
Commercial & Industrial Operations	11.5	-	-	-	-	-	-	-	-	-	-	-	-	-
Procurement & Supply Chain	26.8	6.7	25.0%	0.6	1.9	1.9	0.7	0.5	1.3	0.7	0.4	0.1	0.1	0.3
Total Support Group Expenses	257.0	50.5	19.7%	4.6	14.4	4.1	5.1	4.1	9.5	4.9	2.7	0.9	0.9	2.3
Total OM&A Expenses	810.7	170.9	21.1%	15.5	48.7	7.3	17.1	13.8	32.2	16.6	9.0	2.9	2.9	7.7

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details DISTRIBUTION DEPRECIATION & DEPLETION 2024 Fiscal Base Embedded Cost of Service Study (\$ millions)													
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains	Urban Laterals		Rural Laterals	Transformers		Transformers	Services
				Demand	0.0%		Demand	Customer		Demand	Customer		
Generation Assets													
Power Production	259.9	-	0.0%	-	-	-	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	48.0	-	0.0%	-	-	-	-	-	-	-	-	-	-
Coal Reserves	3.7	-	0.0%	-	-	-	-	-	-	-	-	-	-
Shard Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	311.8	-	0.0%	-	-	-	-	-	-	-	-	-	-
Transmission Assets													
Transmission Assets	81.1	0.9	1.1%	0.9	-	-	-	-	-	-	-	-	-
Total Transmission Assets	81.1	0.9	1.1%	0.9	-	-	-	-	-	-	-	-	-
Distribution Assets													
Distribution Assets	159.8	159.8	100.0%	14.9	-	40.2	11.6	9.2	21.5	14.5	7.8	29.6	-
Meters	6.3	6.3	100.0%	-	-	-	-	-	-	-	-	-	6.3
Instrument Transformers	0.9	0.9	100.0%	-	-	-	-	-	-	-	-	0.9	-
Total Distribution Assets	167.0	167.0	100.0%	14.9	40.2	-	11.6	9.2	21.5	14.5	7.8	29.6	6.3
General Plant Assets													
General Plant Assets	0.0	0.0	21.1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Right of Use Land	0.8	0.2	21.1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Right of Use Buildings	1.0	0.1	27.6%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Office Furniture & Equipment	3.6	1.0	27.3%	0.1	0.3	0.3	0.1	0.1	0.2	0.1	0.1	0.0	-
Vehicles & Equipment	13.4	6.1	45.1%	0.5	1.7	1.7	0.6	0.5	1.1	0.6	0.3	0.1	-
Computer Development & Equipment	38.2	8.8	23.0%	0.8	2.5	2.5	0.9	0.7	1.7	0.9	0.5	0.1	-
Communication, Protection & Control	4.8	0.5	10.0%	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	-
Tools & Equipment	4.6	1.3	28.7%	0.1	0.4	0.4	0.1	0.1	0.2	0.1	0.1	0.0	-
Total General Plant Assets	83.1	22.6	27.2%	2.1	6.4	6.4	2.3	1.8	4.3	2.2	1.2	0.4	-
Total Depreciation & Depletion	642.9	190.5	29.6%	17.8	46.7	-	13.8	11.0	25.7	16.7	9.0	30.0	6.3
													6.6

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details													
DISTRIBUTION OTHER INCOME													
2024 Fiscal Base Embedded Cost of Service Study													
(\$ Millions)													
Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals	
				Demand		Demand		Demand		Demand		Demand	
Other Income													
Customer Services Payment Charges	(8.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Transmission	(4.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Distribution	(7.8)	(7.8)	100.0%	(0.7)	(2.2)	(0.3)	(0.8)	(0.8)	(1.5)	(0.4)	(0.1)	(0.4)	(0.4)
Miscellaneous Other Income	(2.1)	(0.4)	21.1%	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)
Customer Contribution Revenue	(90.2)	(50.7)	56.2%	(0.0)	(1.8)	(0.7)	(1.6)	(2.2)	(5.1)	-	(37.0)	-	(2.2)
Green Power Premium	(0.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(11.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-
CO2 Sales & Penalties	(26.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Other Income	(154.4)	(95.0)	38.2%		(4.2)		(1.1)		(2.5)		(37.2)		(2.6)

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details										
CUSTOMER SERVICE Related Costs										
2024 Fiscal Base Embedded Cost of Service Study										
(\$ Millions)										
Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
Rate Base					Customer	Customer	Customer	Customer	Customer	Customer
Plant In Service (Schedule 2.31)	19,021.2	199.6	1.0%	Functional Class of PIS	16.4	40.9	10.2	49.8	72.9	9.4
Accumulated Depreciation (Schedule 2.32)	(8,729.3)	(53.8)	0.6%	Functional Class of Accum. Depr'n	(6.4)	(10.1)	(2.4)	(14.6)	(17.8)	(2.5)
Allowance For Working Capital	112.8	11.0	9.8%	12.50% of OM&A and Taxes	1.0	2.2	0.5	2.8	3.9	0.5
Inventories (Schedule 2.33)	361.7	(0.3)	-0.1%	Functional Class of Inventories	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
Other Assets (Schedule 2.33)	146.2	12.5	8.5%	Functional Classification of Other Assets	1.1	2.5	0.6	3.2	4.5	0.6
Total Rate Base	10,912.6	169.0	1.5%		12.1	35.5	9.0	41.2	63.4	7.9
Revenue Requirement										
Fuel Expense SaskPower Units	583.1	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	388.3	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(128.9)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.34)	810.7	87.2	10.8%	Functional Class of OM&A	7.9	17.6	4.3	22.3	31.3	3.9
Depreciation & Depletion (Schedule 2.35)	642.9	10.9	1.7%	Functional Class of Depr'n & Depletion	1.0	2.2	0.5	2.8	3.9	0.5
Corporate Capital Tax	57.1	0.8	1.4%	Functional Class of Corp. Capital Tax	0.1	0.2	0.0	0.2	0.3	0.0
Grants in Lieu of Taxes	34.0	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	0.8	0.0	0.7%	Functional Class of Misc. Tax	0.0	0.0	0.0	0.0	0.0	0.0
Other Income (Credit) (Schedule 2.36)	(154.4)	(11.0)	7.1%	Functional Class of Other Income	(0.0)	(2.3)	(5.7)	(2.9)	(0.1)	(0.0)
Return on Rate Base @ 5.70%	622.3	9.6	1.5%	Rate Base	0.7	2.0	0.5	2.3	3.6	0.5
Total Revenue Requirement	2,856.1	97.6	3.4%		9.7	19.6	(0.2)	24.7	39.0	4.8

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES PLANT IN SERVICE 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
				Customer		Customer			
Generation Assets									
Power Production	7,907.0	-	0.0%	-	-	-	-	-	-
Power Production - PPA	1,017.1	-	0.0%	-	-	-	-	-	-
Coal Reserves	72.4	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	6.0	-	0.0%	-	-	-	-	-	-
Total Generation Assets	9,002.5	-	0.0%	-	-	-	-	-	-
Transmission Assets									
Transmission Assets	3,290.6	-	0.0%	-	-	-	-	-	-
Total Transmission Assets	3,290.6	-	0.0%	-	-	-	-	-	-
Distribution Assets									
Distribution Assets	5,250.7	-	0.0%	-	-	-	-	-	-
Meters	117.4	-	0.0%	-	-	-	-	-	-
Instrument Transformers	20.3	-	0.0%	-	-	-	-	-	-
Total Distribution Assets	5,388.4	-	0.0%	-	-	-	-	-	-
General Plant Assets									
Unused Land	2.3	0.3	10.8%	0.0	0.1	0.0	0.1	0.1	0.0
Right of Use Land	9.1	1.0	10.8%	0.1	0.2	0.0	0.2	0.4	0.0
Buildings	638.5	140.2	22.0%	7.9	30.5	7.8	32.9	54.5	6.7
Right of Use Buildings	7.0	1.6	22.6%	0.1	0.3	0.1	0.4	0.6	0.1
Office Furniture & Equipment	55.7	12.2	22.0%	0.7	2.7	0.7	2.9	4.8	0.6
Vehicles & Equipment	221.2	17.5	7.9%	4.5	2.2	0.4	6.1	3.7	0.6
Computer Development & Equipment	197.8	23.0	11.6%	1.8	4.8	1.2	5.7	8.5	1.1
Communication, Protection & Control	184.1	2.9	1.6%	1.0	0.2	-	1.1	0.3	0.4
Tools & Equipment	24.0	1.0	4.1%	0.4	0.1	-	0.4	0.1	0.0
Total General Plant Assets	1,339.8	199.6	14.9%	16.4	40.9	10.2	49.8	72.9	9.4
Total Plant in Service	19,021.2	199.6	1.0%	16.4	40.9	10.2	49.8	72.9	9.4

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details									
CUSTOMER SERVICES ACCUMULATED DEPRECIATION									
2024 Fiscal Base Embedded Cost of Service Study									
(\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
				Customer		Customer			
Generation Assets									
Power Production	(4,345.5)	-	0.0%	-	-	-	-	-	-
Power Production - PPA	(611.1)	-	0.0%	-	-	-	-	-	-
Coal Reserves	(47.1)	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	(4.1)	-	0.0%	-	-	-	-	-	-
Total Generation Assets	(5,007.8)	-	0.0%	-	-	-	-	-	-
Transmission Assets									
Transmission Assets	(1,006.1)	-	0.0%	-	-	-	-	-	-
Total Transmission Assets	(1,006.1)	-	0.0%	-	-	-	-	-	-
Distribution Assets									
Distribution Assets	(2,063.6)	-	0.0%	-	-	-	-	-	-
Meters	(79.9)	-	0.0%	-	-	-	-	-	-
Instrument Transformers	(15.2)	-	0.0%	-	-	-	-	-	-
Total Distribution Assets	(2,158.7)	-	0.0%	-	-	-	-	-	-
General Plant Assets									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Right of Use Land	(3.4)	(0.4)	10.8%	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
Buildings	(70.3)	(14.3)	20.3%	(0.8)	(3.1)	(0.8)	(3.4)	(5.5)	(0.7)
Right of Use Buildings	(4.6)	(1.0)	22.6%	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)	(0.0)
Office Furniture & Equipment	(26.3)	(5.3)	20.3%	(0.3)	(1.2)	(0.3)	(1.3)	(2.1)	(0.3)
Vehicles & Equipment	(130.5)	(10.5)	8.0%	(2.7)	(1.3)	(0.2)	(3.7)	(2.2)	(0.3)
Computer Development & Equipment	(168.4)	(19.6)	11.6%	(1.6)	(4.0)	(1.0)	(4.9)	(7.2)	(0.9)
Communication, Protection & Control	(141.3)	(2.3)	1.6%	(0.8)	(0.1)	-	(0.9)	(0.2)	(0.3)
Tools & Equipment	(11.9)	(0.4)	3.8%	(0.2)	(0.0)	-	(0.2)	(0.0)	(0.0)
Total General Plant Assets	(556.7)	(53.8)	9.7%	(6.4)	(10.1)	(2.4)	(14.6)	(17.8)	(2.5)
Total Accumulated Depreciation	(8,729.3)	(53.8)	0.6%	(6.4)	(10.1)	(2.4)	(14.6)	(17.8)	(2.5)

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES INVENTORIES 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)										

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Inventories									
Power Production - Repair Stores	124.9	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	19.9	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	219.7	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	(2.8)	(0.3)	10.8%	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
Total Inventories	361.7	(0.3)	-0.1%	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES OTHER ASSETS 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)										

Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	26.3	-	0.0%	-	-	-	-	-	-
Intangible Assets	82.2	8.8	10.8%	0.8	1.8	0.4	2.3	3.2	0.4
Prepaid Expenses - Insurance	4.2	0.0	0.6%	0.0	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	33.5	3.6	10.8%	0.3	0.7	0.2	0.9	1.3	0.2
Total Other Assets	146.2	12.5	8.5%	1.1	2.5	0.6	3.2	4.5	0.6

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services OM&A Expenses

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES OM&A EXPENSES 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)									
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Generation Expenses									
Power Plant Operation	226.4	-	0.0%	-	-	-	-	-	-
Power Production Overhead	30.5	-	0.0%	-	-	-	-	-	-
Purchase Power Agreements (PPA)	13.0	-	0.0%	-	-	-	-	-	-
Total Generation Expenses	269.9	-	0.0%	-	-	-	-	-	-
Transmission & Distribution Expenses									
Planning Support	24.3	0.3	1.1%	-	-	-	-	-	0.3
Transmission Including 230/138 & 72 kV Radials	67.4	-	0.0%	-	-	-	-	-	-
Distribution	120.2	-	0.0%	-	-	-	-	-	-
Customer Services	8.8	8.8	100.0%	-	1.0	-	6.2	1.6	-
Metering Services	5.6	5.6	100.0%	5.6	-	-	-	-	-
Total Transmission & Distribution Expenses	226.3	14.6	6.5%	5.6	1.0	-	6.2	1.6	0.3
Customer Services Expenses									
Meter Reading	11.9	11.9	100.0%	-	11.9	-	-	-	-
Billing Services	3.2	3.2	100.0%	-	-	3.2	-	-	-
Collections/Special Collections	1.6	1.6	100.0%	-	-	-	1.6	-	-
Bad Debt Expense	8.3	8.3	100.0%	-	-	-	8.3	-	-
Marketing & Sales	2.6	2.6	100.0%	-	-	-	-	-	2.6
Demand Side Management	8.3	-	0.0%	-	-	-	-	-	-
Customer Service	21.5	21.5	100.0%	-	-	-	-	21.5	-
Total Customer Services Expenses	57.5	49.1	85.5%	-	11.9	3.2	9.9	21.5	2.6
Support Group Expenses									
President / Board	2.2	0.2	10.8%	0.0	0.0	0.0	0.1	0.1	0.0
Corporate & Financial Services (C&FS)	11.3	1.4	12.4%	0.1	0.3	0.1	0.4	0.5	0.1
C&FS - Insurance Premiums & Insurable Losses	19.2	0.1	0.6%	0.0	0.0	-	0.1	0.0	0.0
Asset Management, Planning, & Sustainability	12.8	0.8	6.1%	0.1	0.1	0.0	0.2	0.2	0.0
Integrated Carbon Capture & Sequestration	23.9	-	0.0%	-	-	-	-	-	-
SMR Consortium	0.1	-	0.0%	-	-	-	-	-	-
General Council / Land	7.3	0.8	10.8%	0.1	0.2	0.0	0.2	0.3	0.0
Safety	6.8	0.7	9.7%	0.1	0.1	0.0	0.2	0.2	0.0
Corporate Information & Technology	102.6	12.7	12.4%	1.1	2.6	0.6	3.2	4.6	0.6
Human Resources	32.3	3.5	10.7%	0.4	0.6	0.2	1.0	1.1	0.1
Commercial & Industrial Operations	11.5	-	0.0%	-	-	-	-	-	-
Procurement & Supply Chain	26.8	3.3	12.4%	0.3	0.7	0.2	0.9	1.2	0.1
Total Support Group Expenses	257.0	23.5	9.1%	2.3	4.6	1.1	6.1	8.2	1.0
Total OM&A Expenses	810.7	87.2	10.8%	7.9	17.6	4.3	22.3	31.3	3.9

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details										
CUSTOMER SERVICES DEPRECIATION & DEPLETION										
2024 Fiscal Base Embedded Cost of Service Study										
(\$ Millions)										
Asset Categories		SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
Generation Assets					Customer	Customer	Customer	Customer	Customer	Customer
Power Production		259.9	-	0.0%	-	-	-	-	-	-
Purchase Power Agreements (PPA)		48.0	-	0.0%	-	-	-	-	-	-
Coal Reserves		3.7	-	0.0%	-	-	-	-	-	-
Shand Greenhouse		0.2	-	0.0%	-	-	-	-	-	-
Total Generation Assets		311.8	-	0.0%	-	-	-	-	-	-
Transmission Assets										
Transmission Assets		81.1	-	0.0%	-	-	-	-	-	-
Total Transmission Assets		81.1	-	0.0%	-	-	-	-	-	-
Distribution Assets										
Distribution Assets		159.8	-	0.0%	-	-	-	-	-	-
Meters		6.3	-	0.0%	-	-	-	-	-	-
Instrument Transformers		0.9	-	0.0%	-	-	-	-	-	-
Total Distribution Assets		167.0	-	0.0%	-	-	-	-	-	-
General Plant Assets										
Unused Land		0.0	0.0	10.8%	0.0	0.0	0.0	0.0	0.0	0.0
Right of Use Land		0.8	0.1	10.8%	0.0	0.0	0.0	0.0	0.0	0.0
Buildings		15.6	3.5	22.4%	0.2	0.8	0.2	0.8	1.4	0.2
Right of Use Buildings		2.0	0.4	22.6%	0.0	0.1	0.0	0.1	0.2	0.0
Office Furniture & Equipment		3.6	0.8	22.4%	0.0	0.2	0.0	0.2	0.3	0.0
Vehicles & Equipment		13.4	1.2	8.7%	0.3	0.2	0.0	0.4	0.3	0.0
Computer Development & Equipment		38.2	4.7	12.3%	0.4	1.0	0.2	1.2	1.7	0.2
Communication, Protection & Control		4.8	0.1	1.4%	0.0	0.0	-	0.0	0.0	0.0
Tools & Equipment		4.6	0.2	3.5%	0.1	0.0	-	0.1	0.0	0.0
Total General Plant Assets		83.1	10.9	13.2%	1.0	2.2	0.5	2.8	3.9	0.5
Total Depreciation & Depletion										
		642.9	10.9	1.7%	1.0	2.2	0.5	2.8	3.9	0.5

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details										
CUSTOMER SERVICES OTHER INCOME										
2024 Fiscal Base Embedded Cost of Service Study										
(\$ Millions)										
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer	
Other Income										
Customer Services Payment Charges	(8.5)	(8.5)	100.0%	-	-	(5.7)	(2.8)	-	-	-
Meter Reading	(2.3)	(2.3)	100.0%	-	(2.3)	-	-	-	-	-
Transmission	(4.0)	-	0.0%	-	-	-	-	-	-	-
Distribution	(7.8)	-	0.0%	-	-	-	-	-	-	-
Miscellaneous Other Income	(2.1)	(0.2)	10.8%	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	-	(0.0)
Customer Contribution Revenue	(90.2)	-	0.0%	-	-	-	-	-	-	-
Green Power Premium	(0.7)	-	0.0%	-	-	-	-	-	-	-
Flyash Sales	(11.3)	-	0.0%	-	-	-	-	-	-	-
CO2 Sales & Penalties	(26.6)	-	0.0%	-	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-	-
Total Other Income	(154.4)	(11.0)	7.1%	(0.0)	(2.3)	(5.7)	(2.9)	(0.1)	(0.1)	(0.0)

Schedule 3.0: SaskPower Allocation Methodology Summary

SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology
GENERATION	Demand	Load, Losses and Ancillary Services	Coincident Peak Method (2CP) at output of Generation and step up transformation
	Energy	Load and Losses	Energy plus Losses
TRANSMISSION	DEMAND	Main Grid	2 Coincident Peak Method (2CP) - Coincident Peak at output of transmission.
		230kV & 138kV Radials	2 Coincident Peak Method (2CP) - at output of common 230kV Radials.
		138/72kV Substations	2 Coincident Peak Method (2CP) - at output of substations.
		72kV Radials	2 Coincident Peak Method (2CP) - at output of common 72kV radials.
DISTRIBUTION	DEMAND	Area Substations - Demand	2 Coincident Peak Method (2CP) - at output of substations.
		Distribution Mains - Demand	2 Coincident Peak Method (2CP) - at output of distribution mains.
		Urban Laterals - Demand	2 Coincident Peak Method (2CP) - at output of urban laterals.
		Rural Laterals - Demand	2 Coincident Peak Method (2CP) - at output of rural laterals.
		Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.
		Urban Laterals - Customer	Number of urban customers supplied through laterals.
	CUSTOMER	Rural Laterals - Customer	Number of rural customers supplied through laterals.
		Transformers - Customer	Number of customers supplied through laterals.
		Services - Customer	Direct to classes which are using services.
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.
		Streetlights - Customer	Direct to Streetlight Class.
		Customer Service	Weighted number of customers.
CUSTOMER SERVICES	CUSTOMER	Customer Contributions	Direct to classes which made contribution.
CUSTOMER CONTRIBUTIONS	CUSTOMER		

2CP METHOD

The 2CP(coincident peak) method, allocates costs to rate classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peak. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The non-coincident peak (NCP) method allocates responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occur, to the sum of all the class peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation 2024 Fiscal Base Embedded Cost of Service Study							
Customer Class	Energy Sales GWH	NCP Demand KW	MDD Demand KW	CP Demand KW	NCP Load Factor ¹	MDD Load Factor ²	CP Load Factor ³
Residential	3,224	3,141,507	774,939	622,897	11.68%	47.36%	58.92%
Farms	1,305	785,482	250,202	212,978	18.92%	59.40%	69.78%
Commercial	3,749	1,257,341	606,930	565,884	33.95%	70.32%	75.42%
Power	10,520	1,801,762	1,389,368	1,213,689	66.47%	86.20%	98.68%
Oilfields	4,330	731,489	544,188	511,126	67.39%	90.59%	96.45%
Reseller	1,150	241,192	241,192	204,505	54.28%	54.28%	64.02%
Total	24,278.7	7,958,773.1	3,806,819.0	3,331,078.5	34.73%	72.61%	82.98%

 1 - NCP Load Factor is calculated as follows: $(\text{Energy Sales} * 1,000,000) / (\text{NCP Demand} * 8784)$

 2 - MDD Load Factor is calculated as follows: $(\text{Energy Sales} * 1,000,000) / (\text{MDD Demand} * 8784)$

 3 - CP Load Factor is calculated as follows: $(\text{Energy Sales} * 1,000,000) / (\text{CP Demand} * 8784)$

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class GENERATION Related Costs 2024 Fiscal Base Embedded Cost of Service Study																								
Customer Class	Load ¹		Load ²		Losses ³		Losses ⁴		Scheduling & Dispatch ³		Regulation & Frequency Response ³		Spinning Reserve ³		Supplementary Reserve ³		Planning Reserve ³		Reactive Supply ³		Grants in Lieu of Taxes ⁵		Interruptible Adjustment ³	
	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy
Residential	18.7%	13.3%	28.6%	22.6%	9.1%	8.2%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	19.7%	22.1%	22.1%	19.7%	19.7%
Farms	6.4%	5.4%	9.1%	8.2%	9.1%	8.2%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.9%	6.9%	6.7%	6.7%
Commercial	17.0%	15.4%	25.3%	25.4%	25.3%	25.4%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	17.8%	19.5%	19.5%	17.8%	17.8%
Power	36.4%	43.3%	43.3%	17.9%	15.3%	17.9%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	31.1%	31.1%	34.3%	34.3%
Oilfields	15.3%	17.8%	19.5%	24.1%	19.5%	24.1%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	16.6%	16.6%	15.8%	15.8%
Reseller	6.1%	4.7%	2.2%	1.7%	2.2%	1.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	3.7%	3.7%	5.7%	5.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹ Based on Coincident Peak (ZCP) at the meter.

² Based on actual energy consumption at the meter.

³ Based on Coincident Peak (ZCP) & losses.

⁴ Based on energy/losses.

⁵ Based on Sales Revenue.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class
TRANSMISSION Related Costs
2024 Fiscal Base Embedded Cost of Service Study

Customer Class	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
	Demand	Demand	Demand	Demand
Residential	19.7%	14.5%	29.9%	29.9%
Farms	6.7%	5.0%	10.0%	10.0%
Commercial	17.8%	13.0%	27.3%	27.3%
Power	34.3%	52.5%	10.1%	10.1%
Oilfields	15.8%	12.7%	22.3%	22.3%
Reseller	5.7%	2.4%	0.5%	0.5%
Total	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on Coincident Peak (2CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class DISTRIBUTION Related Costs 2024 Fiscal Base Embedded Cost of Service Study																												
Customer Class	Area Substations ¹		Distribution Mains ¹		Urban Laterals ¹		Urban Laterals ²		Rural Laterals ¹		Rural Laterals ³		Transformers ⁴		Transformers ⁵		Services ⁶		Instrument Transformers ⁷		Amortization Customer Contributions ⁸		Meters ⁹		Streetlights ¹⁰			
	Demand		Demand		Demand		Customer		Demand		Customer		Demand		Customer		Customer		Customer		Customer		Customer		Customer		Customer	
Residential	33.1%		33.2%		22.8%		87.8%		9.9%		43.8%		30.3%		74.6%		31.3%		0.0%		20.1%		56.5%		0.0%		0.0%	
Farms	11.1%		11.1%		0.0%		0.0%		19.7%		34.5%		11.6%		10.4%		11.3%		0.5%		31.6%		10.3%		0.0%		0.0%	
Commercial	29.3%		29.4%		77.2%		12.2%		19.8%		10.1%		32.4%		11.5%		39.4%		85.2%		39.1%		24.6%		100.0%		0.0%	
Power	2.4%		2.4%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		1.4%		0.0%		0.0%	
Oilfields	23.9%		24.0%		0.0%		0.0%		50.6%		11.5%		25.7%		3.5%		18.0%		1.3%		9.2%		7.1%		0.0%		0.0%	
Reseller	0.3%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.7%		0.0%		0.7%		0.0%		0.1%		0.0%		0.0%	
Total	100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%		100.0%	

¹ Based on Coincident Peak (NCP) & losses.² Based on the number of urban customers in each customer class. Urban streetlights are based on 6 lights per circuit.³ Based on the number of rural customers in each customer class. Rural streetlights are based on 3 lights per circuit.⁴ Based on Non Coincident Peak (NCP) & losses.⁵ Based on the number of customers with transformer-related equipment in each customer class. Streetlights are based on 6(urban) & 3(rural) lights per circuit.⁶ Based on the number of customers in each customer class supplied through services weighted by installed cost of a service.⁷ Based on the number of customers with transformer-related equipment in each customer class.⁸ Based on customer contributions in each customer class.⁹ Based on the new capital cost of meters and instrument transformers multiplied by the number of customers in the customer class.¹⁰ Direct to the streetlight class.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class CUSTOMER SERVICE Related Costs 2024 Fiscal Base Embedded Cost of Service Study						
Customer Class	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
	Customer	Customer	Customer	Customer	Customer	Customer
Residential	20.4%	73.2%	56.0%	87.0%	67.6%	11.8%
Farms	3.7%	15.8%	10.1%	6.0%	12.1%	9.1%
Commercial	27.6%	6.8%	18.0%	6.0%	11.8%	19.0%
Power	22.7%	0.0%	2.3%	0.0%	2.6%	31.7%
Oilfields	25.1%	4.2%	13.6%	1.0%	5.7%	27.8%
Reseller	0.5%	0.0%	0.1%	0.0%	0.1%	0.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on the department responsible's estimate of labour time spent on each customer class.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class GENERATION Related Costs 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)																				
Customer Class	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Losses	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve		Reactive Supply	Grants in Lieu of Taxes		Interruptible Adjustment
				Demand	Energy	Demand	Energy		Demand	Energy		Demand	Energy		Demand	Energy		Demand	Energy	
Residential	644.4	303.9	47.2%	85.2	150.9	13.7	21.1	21.1	2.8	1.5	4.2	6.3	7.0	3.5	7.6	-	-	-	-	-
Farms	209.3	113.2	54.1%	29.1	61.1	4.4	7.6	7.6	0.9	0.5	1.4	2.1	2.4	1.2	2.4	-	-	-	-	-
Commercial	544.8	318.4	58.4%	77.4	175.5	12.1	23.7	23.7	2.5	1.4	3.8	5.7	6.4	3.2	6.7	-	-	-	-	-
Power	855.3	737.5	86.2%	166.1	492.5	7.4	16.7	16.7	4.8	2.6	7.3	11.0	12.3	6.1	10.7	-	-	-	-	-
Oilfields	494.3	330.5	66.9%	69.9	202.7	9.4	22.5	22.5	2.2	1.2	3.4	5.0	5.6	2.8	5.7	-	-	-	-	-
Reseller	107.9	93.1	86.3%	28.0	53.8	1.1	1.6	1.6	0.8	0.4	1.2	1.8	2.1	1.0	1.3	-	-	-	-	-
Total	2,856.1	1,896.6	66.4%	455.8	1,136.7	47.9	93.3	93.3	14.0	7.7	21.3	32.0	35.8	17.8	34.3	-	-	-	-	-

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class											
TRANSMISSION Related Costs											
2024 Fiscal Base Embedded Cost of Service Study											
(\$ Millions)											
Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid	230 kV Radials	230/138 kV Substations	138 kV Lines Radials				
					Demand	Demand	Demand				
Residential	644.4	69.2	10.7%	44.9	6.6	6.3	11.4				
Farms	209.3	23.4	11.2%	15.2	2.3	2.1	3.8				
Commercial	544.8	62.7	11.5%	40.6	5.9	5.8	10.4				
Power	855.3	107.9	12.6%	78.2	23.8	2.1	3.8				
Oilfields	494.3	54.9	11.1%	35.9	5.7	4.7	8.5				
Reseller	107.9	14.5	13.4%	13.1	1.1	0.1	0.2				
Total	2,856.1	332.6	11.6%	227.9	45.3	21.1	38.2				

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class																		
DISTRIBUTION Related Costs																		
2024 Fiscal Base Embedded Cost of Service Study																		
(\$ Millions)																		
Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streetlights
				Demand		Demand		Demand	Customer	Demand	Customer	Demand	Customer					
Residential	644.4	206.7	32.1%	17.8	50.6	4.2	37.7	3.3	34.4	15.8	21.0	17.0	-	-	-	-	4.9	-
Farms	209.3	62.7	29.9%	5.9	16.9	-	-	6.6	27.1	6.1	2.9	(38)	0.0	-	-	-	0.9	-
Commercial	544.8	152.8	28.0%	15.7	44.8	14.2	5.2	6.6	8.0	16.9	3.3	16.4	1.0	-	-	-	2.1	18.5
Power	852.3	5.2	0.6%	1.3	3.6	-	-	-	-	-	-	-	0.1	-	-	-	0.1	-
Oilfields	494.3	101.8	20.6%	12.8	36.6	-	-	17.0	9.0	13.4	1.0	11.3	0.0	-	-	-	0.6	-
Reseller	107.9	0.2	0.2%	0.2	-	-	-	-	-	-	-	-	0.0	-	-	-	0.0	-
Total	2,856.1	529.2	18.5%	53.7	152.6	18.4	42.9	33.6	78.4	52.3	28.2	40.9	1.2	-	-	-	8.6	18.5

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class CUSTOMER SERVICE Related Costs 2024 Fiscal Base Embedded Cost of Service Study (\$ Millions)										
Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning	
				Customer	Customer	Customer	Customer	Customer	Customer	
Residential	644.4	64.7	10.0%	2.0	14.4	(0.1)	21.5	26.4	0.6	
Farms	209.3	10.1	4.8%	0.4	3.1	(0.0)	1.5	4.7	0.4	
Commercial	544.8	11.0	2.0%	2.7	1.3	(0.0)	1.5	4.6	0.9	
Power	855.3	4.8	0.6%	2.2	-	(0.0)	-	1.0	1.5	
Oilfields	494.3	7.1	1.4%	2.4	0.8	(0.0)	0.2	2.2	1.3	
Reseller	107.9	0.1	0.1%	0.1	-	(0.0)	-	0.0	0.0	
Total	2,856.1	97.6	3.4%	9.7	19.6	(0.2)	24.7	39.0	4.8	

Schedule 7.0: Customer Data for Rate Design

Customer Data				
2024 Fiscal Base Embedded Cost of Service Study				
Customer Class	Average Annual # of Accounts	Annual Revenue (\$)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)
Residential	413,013	631,617,628	3,223,811	-
Farms	57,642	197,987,671	1,305,435	2,128,519
Commercial	65,106	556,555,012	3,749,106	12,624,965
Power	132	894,399,613	10,520,123	18,607,740
Oilfields	19,255	469,861,017	4,330,200	9,139,658
Reseller	3	105,670,387	1,150,050	2,289,110
Total	555,151	2,856,091,327	24,278,725	44,789,992

2026 FISCAL TEST EMBEDDED COST OF SERVICE STUDY

PREPARED BY:

Pricing & Costing

of

Pricing & Energy Forecasting

Submitted On:

December 22, 2025

❖ BASED ON 2026-27 FISCAL BUSINESS PLAN FORECASTED FINANCIAL STATEMENTS AND SCHEDULES

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I. INTRODUCTION

A. Purpose

The SaskPower 2026 Fiscal (2026F) Test Cost of Service Study provides an in-depth, detailed account of the annual cost to serve each of SaskPower's customer classes at the end of the forecasted fiscal year (ending March 31, 2026). The primary purpose is to provide an indication of the extent by which revenues contributed from a particular class, recover the allocated costs of serving that customer class.

To remain viable, SaskPower must be given the opportunity to recover its incurred costs of providing electric service to its various classes of customers. Cost of service is usually defined to include all a utility's operating expenses, plus a reasonable return on its investment ("rate base") devoted to the service of the rate paying public. These stakeholders and their interests are as follows:

1. **Saskatchewan Rate Review Panel (SRRP):** The Saskatchewan Rate Review Panel is interested in assuring that SaskPower only includes costs and returns that are related to SaskPower's core business. They are also interested in assuring that SaskPower applies methodologies that are reasonable and acceptable. The SRRP also relies on the opinion of an external consultant to report on the reasonableness of the embedded Cost of Service Study.
2. **SaskPower Management / Executive / Board:** SaskPower's Executive, Management, and Board are interested in ensuring that the corporation's financial targets are achieved. The cost of service model is vital to the development of rates and achieving SaskPower's revenue requirement.
3. **Customers:** The cost of service provides documentation to these stakeholders in terms of how much of the cost to provide them with service is recovered through the rates they pay.

B. Scope

A Cost of Service Study is a study of the costs incurred by SaskPower in producing, transmitting, and distributing electricity to its customers, by customer class, in relation to revenues collected from each class under existing rates. For this report the costs analyzed are the forecasted "embedded" costs of the existing plant and expenses in the fiscal "**Test year**" of **2026**.

NorthPoint Energy Solutions is a SaskPower owned subsidiary company. The financial assets and expenses from this subsidiary have been included in this year's cost of service study. Best

practices from other utilities across Canada have shown it is prudent to rate payers for a utility to include subsidiary financial results in years when the subsidiary achieves a net gain. In years of net loss, subsidiaries will not be included in the Cost of Service Study.

C. Objectives

Cost of service studies are among the basic tools of ratemaking. While non-cost concepts and principles can modify the cost-based standard, cost of service methodology remains the primary factor in determining the reasonableness of rates. SaskPower's key objectives of the cost-of-service study and resulting rate design are as follows:

1. Meeting Revenue Requirement
2. Fairness and Equity
3. Economic Efficiency
4. Conservation of Resources
5. Simplicity and Administrative Ease
6. Stability and Gradualism

Meeting Revenue Requirement

Meeting the revenue requirement suggests that SaskPower's customer rates are designed with the purpose to provide sufficient revenue to cover both the utility's forecasted annual costs and return on rate base. Annual costs and the return on rate base are further explained within Step 1 of the Identification section of the cost of service methodology.

Fairness and Equity

Fairness and equity imply that SaskPower's cost of service methodology and rate design is applied to the various customer classes, based on cost behaviour drivers and cost causality, while projecting no undue discrimination between customers.

Economic Efficiency

Economic efficiency refers to SaskPower's objective of utilizing assets and expenses in a manner that is operationally effective for developing a power system, while the rates charged for electrical service provide the appropriate price signals to customers that will allow SaskPower to maintain a power system that continues to be efficient over time.

Conservation of Resources

Conservation of resources relies on asset and cost allocations that provide appropriate price signals to consumers, so that they will utilize power in a reasonable manner while considering SaskPower's cost of providing power and the value placed on that power by the various customer classes.

Simplicity and Administrative Ease

Simplicity and administrative ease objectives for ratemaking rely on concepts of allocation that are logical, transparent to stakeholders and customers, and easily implementable.

Stability and Gradualism

Stability and gradualism objectives aspire to employ cost allocations and rate-making standards that are steady over longer periods. Stability and gradualism goals avoid non-typical volatility of rates to any customer classes at any given time.

Since the above objectives do not always agree with the concept that service should be provided on a cost basis, SaskPower must use judgement and the advice of our shareholder and Cabinet as to the appropriate courses of action.

D. Cost of Service Methodology Changes

The latest review of SaskPower's cost of service and rate design methodology occurred in 2023 (January - June). The review was conducted by Elenchus Research Associates, from Toronto, Ontario.

Elenchus filed its final report on June 30, 2023, which stated, in their view, SaskPower's current cost allocation methodology is consistent with accepted rate making principles and practices, is consistent with methodologies commonly used by other electric utilities, and is reflective of SaskPower's operational circumstances, with some recommendations for enhancements:

1) Removal of the coincident peak allocation methodology (Bary correction) in rate design.

SaskPower previously employed an adjustment when designing rates for classes of customers where customers load factors and coincidence factors varied. Within these classes of customers, high load factor customers typically have higher coincidence factors, meaning they consume more electricity consistently, and particularly at system peak, resulting in more capacity costs.

The Bary correction's main purpose was to shift some of the demand-related costs to be recovered through the energy charge. This adjustment was also beneficial in being more equitable with cost causality, where customers were being billed for costs that they were responsible for causing.

The unintended effect was a distorted price signal for energy and demand charges, where inflated energy charges and lower demand charges provided an incorrect price signal for customers to defect from the grid and/or self-generate, to avoid the higher

energy charges. These signals gave an inadvertent effect of shifting demand costs from self-generation customers to other SaskPower customers who did not create the burden of these costs.

Starting in 2022, SaskPower gradually began phasing out the Bary correction within its rate design and Elenchus supports this change.

2) Further investigate the deployment of Time of Use (TOU) rates as a means to managing the demand with the intention of minimizing the need for new capacity.

TOU rates have been implemented by various utilities in a response to providing an accurate price signal to customers for consuming electricity at varying times of a day, and/or season with the intention of reducing generation costs which cascade to lower utility costs and ultimately, lower bills for customers. The purpose of TOU rates is to influence customers to change their electricity consumption behaviours from high-cost periods to low-cost periods, which allows a power utility to reduce its total costs during peak periods or during periods of higher expense incurred periods.

For TOU rates to be utilized, more Advanced Metering Infrastructure (AMI) needs to be deployed including proper metering, and billing systems, along with appropriate economic differentials in marginal cost that utilities can present to entice customers to shift their demand and reduce a utility's average cost of power.

With SaskPower's inherent system load factor of 75% at this current time, and projected new load relatively being flat, there is minimal opportunity for SaskPower to shift load. Elenchus recommended a continuation with current rate structure, but if conditions change and marginal costs increase, SaskPower should consider a move to TOU rates.

3) Rate Alignment options

SaskPower employs a typical rate structure for all classes that aligns rate components (e.g. fixed charges, demand charges and energy charges) with their corresponding classified costs (customer-related, demand-related and energy-related) where it is feasible, based on metering technology availability, while avoiding unintended consequences like rate shock.

As mentioned previously, Elenchus expressed concerns of the Bary correction's inherent misalignment of revenue and cost-driven price signals that motivated self-generation/grid defection that shifted the burden to other SaskPower customers who did not incur those costs. This violates SaskPower's objectives of fairness/equity, and economic efficiency, and can lead to stranded assets for the utility.

Implementation of demand charges for all customer classes utilizing coincident peak demand is a potential option but is not economically practical for low demand customers as it requires Advanced Metering Infrastructure (AMI) equipment. Also, price signals can be difficult for customers to respond to appropriately, especially if they have no lead time to reduce their demand.

Another option Elenchus provided would be to assign a portion of demand-related costs within a basic monthly charge. Although this would increase revenue and bill stability, assigning demand-related costs within the basic monthly charge would be inequitable to customers with lower consumption and demand such as low-income customers and seasonal customers.

SaskPower's current rate methodology for customers without demand charges, such as the Residential class, does recover demand-related costs within the energy charge, and follows a standardized practice across utilities. Elenchus acknowledges that a change from this practice would provide an inappropriate price signal to customers, particularly in scenarios where costs derived from consumption and demand are greater than variable revenue recovered from the customer.

After reviewing the options SaskPower has available, Elenchus recommended that SaskPower continue to utilize its current rate design practices for customer classes without demand charges, while continuing to identify its rate structure once AMI billing data has been implemented.

E. Financial Reporting Changes affecting 2026

Minimal financial reporting changes were made, which impact the 2026 Fiscal Test Forecasted financial information. The following are of note:

- 1) The Streetlight class is reported financially within the Commercial class and the Power – Contract class is being reported financially within the Power class. These amendments align to SaskPower's current financial reporting structure.
- 2) As of April 1, 2025, the provincial government directed SaskPower to stop collecting the Federal Carbon Tax from its customers.

Previously, as of April 1, 2019, the federal government implemented a Carbon Tax on fossil fuel emissions based on their carbon pollution pricing system, retroactive to January 1, 2019. The Federal Carbon Tax is based on predetermined emission thresholds set by the federal government on an annual calendar basis.

Until April 1, 2025, SaskPower elected to recover the Federal Carbon Tax through separate rate riders based on customers' energy consumption (kWh), rather than incorporating it into its published rates. As a result of this approach, expenses and revenue related to the carbon tax have never been included in the Cost-of-Service Study. Consequently, the suspension of carbon tax collection does not affect the results of the Cost-of-Service Study.

- 3) All Purchased Power Agreement (PPA's) assets are reported as a separate line item within the Cost-of-Service report, functionalized within Generation.
- 4) Organizational realignment of various Business units occurred throughout 2024 as follows:
 - SaskPower has consolidated NorthPoint, Generation, Transmission and Distribution into one business unit called Operations. Similarly, Asset Management, Technology & Security, and Finance have been consolidated under one business unit called Strategy, Technology & Finance. Procurement and Customer Experience (previously called Customer Services) have also been combined into a business unit called Customer Experience and Procurement. Although these units are now reporting from different areas, their rate base and expenses are still functionalized and classified in the same manner as they were previously.

F. Calculation of the Return on Rate Base

The Return on Rate Base (RORB) is the return, expressed as a percentage, which SaskPower will earn on the net book value of its assets required to produce, transmit and distribute electricity to its customers, after expenses. SaskPower's RORB is directly tied to its Return on Equity (ROE) performance and is based on achieving its targeted ROE of 8.5%.

The system RORB is calculated based on SaskPower's actual (or forecasted) revenues, expenses, and rate base for the fiscal year. The tables below show the calculation of SaskPower's RORB derived from the 2026 Fiscal Test Cost of Service:

SaskPower Return on Rate Base Inputs/Supporting Calculations as of March 31, 2026
2026 Fiscal Test Embedded Cost of Service Study
(\$ Millions)

Indicator	Item:	2026 Fiscal Test	Calculation Details:
	<u>From SaskPower's Cost of Service</u>		
a)	Total Rate Base	12,888.0	
b)	Electricity Sales Revenue	3,016.4	
c)	Other revenues (incl. Export & Electricity Trading)	<u>184.0</u>	
d)	Total Sales Revenue	<u>3,200.4</u>	b + c
e)	Total Expenses	<u>2,609.3</u>	
f)	Operating Income Before Finance Charges	<u>591.1</u>	d - e
g)	Finance Charges	<u>462.5</u>	
h)	Operating Income	<u>128.6</u>	f - g
i)	Return on Rate Base - Finance Charges	3.6%	g / a
j)	Return on Rate Base - Return	<u>1.0%</u>	h / a
k)	Total Return on Rate Base	<u>4.6%</u>	f / a
	<u>From SaskPower's Financial Statements</u>		
l)	Long Term Debt	9,453.7	
m)	Current Portion of Long Term Debt	0.0	
n)	Finance Lease Obligations	892.8	
o)	Current Portion of Lease Obligations	(51.2)	
p)	Short Term Advances	1,109.1	
q)	Debt Retirement Funds	(983.6)	
r)	Cash & Cash Equivalents	<u>43.9</u>	
s)	Total Debt	<u>10,464.7</u>	l + m + n + o +
t)	Retained Earnings	2,165.9	
u)	Equity Advances	593.0	
v)	Total Equity	<u>2,758.9</u>	t + u
w)	Total Debt & Equity	<u>13,223.6</u>	s + v
x)	Debt %	79.1%	s / w
y)	Equity %	20.9%	v / w

SaskPower 2026 Fiscal Test Return on Rate Base as of March 31, 2026
2026 Fiscal Test Embedded Cost of Service Study
(\$ Millions)

	Amount	Capital Structure	Cost of Capital	Component Weighted Cost of Capital
Debt	10,464.7	79.14% *	4.53%	= 3.59%
Equity	2,758.9	20.86% *	4.78%	= 1.00%
Total	13,223.6	Return on Rate Base		4.59%

Please note that within the Cost-of-Service Return on Equity (ROE) calculation, unlike within the ROE calculation within SaskPower's Financial Statements, equity earnings are not included.

G. Cost of Service to Business Plan Reconciliation

Due to differences between IFRS accounting standards and the National Association of Regulatory Utility Commissioner's (NARUC) electric utility cost allocation standards, an Income Statement and a Balance Sheet reconciliation that highlights the difference between the two is included below:

Fiscal Test Income Statement - Cost of Service to Forecasted Business Plan Financial Statements Reconciliation
(\$ Millions)

	2026 Fiscal Test		
	Income Statement	Adjustment	Cost of Service
REVENUE			
Saskatchewan Sales	\$2,922.1	\$94.32 *	\$3,016.4
Federal Carbon Revenue	\$187.1	(\$187.1)	\$0.0
Export + Electricity Trading	\$51.9	(\$51.9)	\$0.0
Other Income (Does Not Include SPI Equity Earnings)	\$132.1	(\$132.1)	\$0.0
Total Revenue	\$3,293.2	(\$276.8)	\$3,016.4
EXPENSES			
Fuel & Purchased Power			
Fuel	\$589.4		\$589.4
Purchased Power	\$258.5		\$258.5
Federal Carbon Charge Expense	\$368.1	(\$368.1)	\$0.0
Total Fuel and Purchased Power	\$1,216.0	(\$368.1)	\$847.9
Less Export & Net Electricity Trading Revenue		(\$51.9)	(\$51.9)
Total Fuel & Purchased Power After Export Revenue	\$1,216.0	(\$420.0)	\$796.0
Total OM&A	\$932.9		\$932.9
Total Depreciation & Other Expenses	\$723.1		\$723.1
Finance Charges	\$462.5	(\$462.5)	\$0.0
Total Taxes	\$105.4		\$105.4
Total Other Income	(\$132.1)	(\$132.1)	(\$132.1)
Total Expenses	\$3,307.8	(\$1,014.6)	\$2,425.3
Operating Income	(\$14.6)	\$737.8	\$591.1
Rate Base			\$12,888.0
Return on Rate Base			4.59%

Reconciliation to Audited Financial Statements:

Operating Income for the Cost of Service before Adjustments	\$591.1
add: Federal Carbon Tax Revenue	\$187.1
less: Finance Charges	(\$462.5)
Foreign Exchange Gains/Losses	\$0.0
Federal Carbon Charge Expense	(\$368.1)
Operating Income Before Adjustments	(\$52.4)
less: Adjustment to Full Year Revenue due to Timing of Rate Application *	(\$94.3)
Net Income as per the Audited Financial Statements	(\$146.7)

* Saskatchewan Sales Revenue was adjusted in the Cost of Service model to include the full 12 months of the proposed revenue lift for the fiscal year, reflecting an effective date of April 1st, 2026.

** numbers may differ due to immaterial rounding

Fiscal Base Balance Sheet - Cost of Service to Forecasted Business Plan Financial Statements Reconciliation
(\$ Millions)

Reconciliation to Audited Financial Statements:	2026 Fiscal Test
Rate Base from the Cost of Service before Adjustments <i>(see Schedule 1.0)</i>	\$12,888.0
add: Current Assets Net of Inventories, Prepaid, & Risk Mgmt Assets	\$546.1
Equity Investments	\$0.0
Debt Retirement Funds	\$983.6
Construction in Progress	\$1,752.3
Risk Management Assets (unrealized)	\$0.0
less: Working Capital Adj	(\$129.8)
Total Assets as per the Audited Financial Statements *	\$16,040.2

* numbers may differ due to immaterial rounding

II. SUMMARY OF RESULTS

Tables 1, 2, and 3 outline the summary results from the 2026 Fiscal Test Cost of Service Study.

- **Table 1 – Summary of Functionalized Revenue Requirement**
This table identifies the cost of service by function (Generation, Transmission, Distribution, and Customer Service).
- **Table 2 – Summary of Classified Revenue Requirement**
This table identifies the cost of service by billing component for each customer class. The breakdown mimics the rate structure for all customer classes.
- **Table 3 – Summary of Revenue-to-Revenue Requirement Ratios**
This table displays the breakdown of Revenue-to-Revenue Requirement Ratio by customer class.

Table 1 – Summary of Functionalized Revenue Requirement

Summary of Functionalized Revenue Requirement by Customer Class 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Customer Class	Total Company (\$)	Generation		Transmission		Distribution		Customer Service	
		(\$)	(%)	(\$)	(%)	(\$)	(%)	(\$)	(%)
Residential Farms	685.1	325.9	47.6%	72.3	10.6%	207.9	30.4%	78.9	11.5%
	211.7	116.0	54.8%	23.0	10.9%	60.3	28.5%	12.3	5.8%
Commercial	572.7	344.1	60.1%	64.3	11.2%	151.3	26.4%	13.0	2.3%
Power	928.8	801.7	86.3%	116.8	12.6%	4.8	0.5%	5.5	0.6%
Oilfields	510.1	349.8	68.6%	54.3	10.7%	97.8	19.2%	8.2	1.6%
Reseller	108.2	94.3	87.2%	13.6	12.5%	0.2	0.2%	0.1	0.1%
Total	3,016.4	2,031.7	67.4%	344.3	11.4%	522.3	17.3%	118.0	3.9%

Table 2 – Summary of Classified Revenue Requirement

Summary of Classified Revenue Requirement by Customer Class 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)						
Customer Class	Total Company (\$)	Demand Related		Energy Related		Customer Related
		(\$)	(%)	(\$)	(%)	(\$)
Residential	685.1	292.8	42.7%	198.4	29.0%	193.9
Farms	211.7	98.5	46.5%	75.3	35.6%	37.8
Commercial	572.7	275.9	48.2%	230.8	40.3%	66.0
Power	928.8	341.6	36.8%	581.5	62.6%	5.8
Oilfields	510.1	230.1	45.1%	253.6	49.7%	26.4
Reseller	108.2	47.5	43.9%	60.5	55.9%	0.2
Total	3,016.4	1,286.4	42.6%	1,400.1	46.4%	330.0
						10.9%

Table 3 – Summary of Revenue-to-Revenue Requirement Ratios

Summary of Revenue to Revenue Requirement Ratios 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)			
Customer Class	Revenue (\$)	Revenue Requirement (\$)	Revenue to Revenue Requirement Ratio
Residential	670.6	685.1	0.98
Farms	201.0	211.7	0.95
Commercial	598.4	572.7	1.04
Power	947.6	928.8	1.02
Oilfields	495.0	510.1	0.97
Reseller	103.9	108.2	0.96
Total (System)	3,016.4	3,016.4	1.00

III. COST OF SERVICE METHODOLOGY

The study follows a five-step process:

- The first step is to **identify** in detail the accounting costs that are to be allocated to customer classes.
- The second step is to **functionalize** the costs between generation, transmission, distribution, and customer services functions.
- The third step is to **classify** each set of functionalized costs into demand, energy, and customer components.
- The fourth step is to **allocate** the functionally classified costs among the several customer classes.
- The fifth step is to **compare** between the allocated costs and the revenues collected from the customer classes to arrive at the revenue to cost ratios.
- The sixth step is to **create** ideal rates for each class of customers so that the appropriate amount of revenue is collected based on the class's costs.

STEP 1: IDENTIFICATION

The initial step is to identify the accounting costs to be included in the Cost-of-Service Study. SaskPower's Finance Business Unit supplies the 2026 Fiscal Year End Consolidated Financial Summary.

Three types of accounts are separately identified in detail:

1. Rate Base Items – investments and liabilities as reported in SaskPower's Balance Sheet. Please refer to **Schedule 1.0** for summary of these items as well as the forecasted data for the 2026 Fiscal Test Year. Data is reported for the year end in the following categories:

- Plant in Service
- Accumulated Depreciation
- Allowance for Working Capital
- Inventories
- Other Assets

Plant in Service is reported in more detail by function: Generation - by type of generation, Transmission - by voltage level, Distribution Plant - by type of plant, and General & Intangible Plant - by primary usage (unused land, buildings, office furniture and equipment, vehicles & equipment, computer development & equipment, communication, protection & control, and tools and equipment).

Contributions in Aid of Construction were previously netted against Fixed Assets as part of the Rate Base and amortized over the estimated service life of the related asset. The amortization of these contributions was netted against Depreciation Expense under GAAP. However, with the adoption of IFRS accounting standards in 2011, Contributions in Aid of Construction is recognized immediately as Other Income when the related fixed asset is available for use.

2. Revenue Requirement – this is a calculation of annual costs (from SaskPower’s Income Statement) plus the Return on Rate Base (calculated as Rate Base multiplied by the system average Return on Rate Base percentage). The system average Return on Rate Base is equal to total revenue minus total expenses divided by the total rate base. Please refer to **Schedule 1.0** for a summary of these items as well as the forecasted data for the 2026 Fiscal Test Year. Data is reported for the year end in the following categories:

- Fuel
- Purchased Power
- Export Revenue (Credit)
- Operating, Maintenance, & Administration (OM&A)
- Depreciation and Depletion
- Corporate Capital Tax
- Grants In Lieu of Taxes
- Miscellaneous Tax
- Other Operating Revenues (Credit)
- Return on Rate Base (Rate Base multiplied by the system average Return on Rate Base)

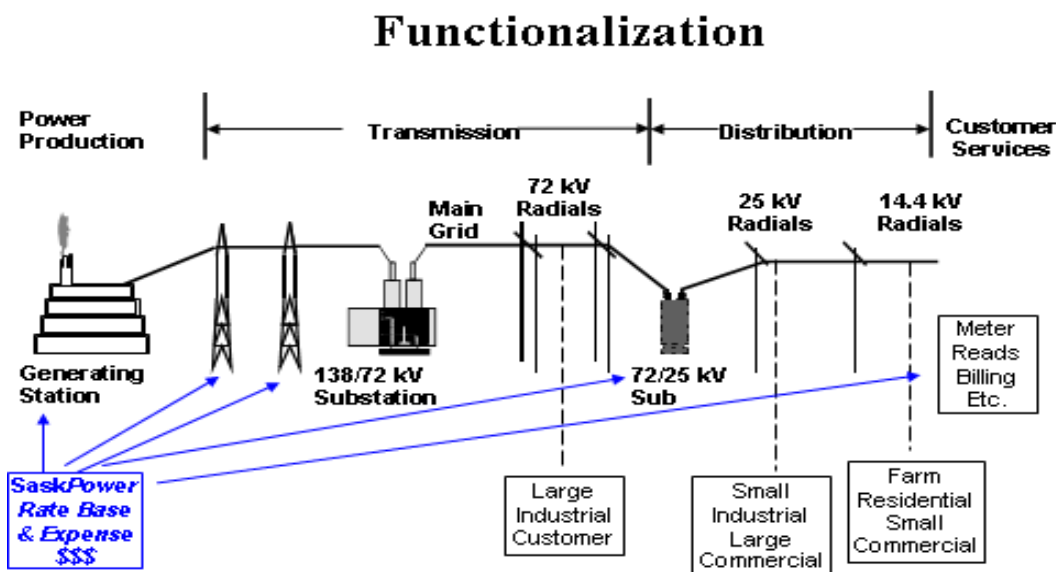
3. Revenue Items - annual domestic sales revenues as reported on SaskPower’s Income Statement. For forecast (Test) years, the SaskPower Load & Revenue Forecasting department provides a projection of net sales within Saskatchewan. **Schedule 7.0** provides a summary by customer class of the actual revenues for the 2026 Fiscal Test Year.

STEP 2: FUNCTIONALIZATION

The second step is to functionalize all accounting costs, in terms of plant and expenses into the major functions of SaskPower's integrated electric system. Please refer to **Figure 1** for a schematic of the process. Rate base and expenses are assigned to the following functions and sub functions:

1. Generation Load Losses Scheduling & Dispatch Regulation & Frequency Response Spinning Reserve Supplementary Reserve Planning Reserve Reactive Supply Grants in Lieu of Taxes	3. Distribution Area Substations Distribution Mains Urban Laterals Rural Laterals Transformers Services Instrument Transformers Meters Streetlights Customer Contributions
2. Transmission Main Grid 230kV & 138kV Lines Radials 138kV/72kV Substations 72kV Lines Radials	4. Customer Service Metering Services Meter Reading Billing & Customer Accounts Customer Collecting Service & Support Customer Strategy & Planning

Figure 1: Functionalization Schematic



Please refer to **Schedules 2.00 through to 2.36** for the functionalization of the financial accounting details. A summary of the functionalization methodology is summarized below for rate base and revenue requirement which includes annual expense items from the income statement and return on rate base.

1. Rate Base Items

1.1 - Plant in Service & Accumulated Depreciation

- **SaskPower Generation, Transmission, and Distribution:**
All the rate base accounts are functionalized based on the plant designation; generation plant is functionalized entirely to the generation function; transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for Wind Projects is included within SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.
- **Coal Reserves:**
SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

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- **Shand Greenhouse:**
The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.
 - **Purchased Power Agreements:**
The assets associated with Purchased Power Agreements are functionalized to generation.
 - **Meters and Instrument Transformers:**
Meters and instrument transformers are included in the meters and instrument transformers sub-function within distribution.
 - **General Plant - Unused Land:**
The functionalization and sub-functionalization of unused land is done using OM&A expense.
 - **General Plant – Right of Use Land:**
The functionalization and sub-functionalization of right-of-use land is done using OM&A expense.
 - **General Plant – Buildings:**
The functionalization and sub-functionalization of the SaskPower head office building and all other buildings is done using OM&A expense.
 - **General Plant – Right of Use Buildings:**
The functionalization and sub-functionalization of right-of-use buildings is done using OM&A expense derived from buildings, excluding Head Office, Research & Development, Storage and Residential Buildings.
 - **General Plant - Office Furniture & Equipment:**
The functionalization and sub-functionalization of office furniture and equipment utilizes OM&A expense for buildings.
 - **General Plant - Vehicles & Equipment:**
The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit centre. The asset values for vehicles and equipment are then prorated to sub-functions within each function using OM&A expense.

- **General Plant - Computer Development & Equipment:**

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) are functionalized on an application-by-application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using OM&A expense.

- **General Plant - Communication, Protection & Control Equipment:**

Communication, Protection & Control Equipment is functionalized to generation, transmission, distribution, and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

- **General Plant - Tools & Equipment:**

The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using OM&A expense.

1.2 - Allowance for Working Capital

- The allowance for working capital is consistent with Cost-of-Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working capital is calculated as 12.5% of the sum of OM&A expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.3 - Inventories

- SaskPower accounting records summarize inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within the generation, transmission and distribution functions using OM&A expense.

1.4 - Other Assets

- Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

- **Natural gas / coal-related:**
Functionalized to generation.
- **Employee-related:**
Functionalized using head count by Business Unit / Support Group.
- **Insurance expense-related:**
Functionalized using information provided from SaskPower's risk management staff.
- **Miscellaneous:**
Prorated to sub-functions within each function using OM&A expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below:

2.1 - Fuel Expense SaskPower Units

- The fuel expense for SaskPower units is functionalized 100% to generation.

2.2 - Purchased Power and Import

- The purchased power expense is functionalized 100% to generation.

2.3 - Export & Net Electricity Trading Revenue

- Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.4 - Operating, Maintenance & Administration (OM&A) Expense

- **Power Production Business Unit:**
The OM&A expenses for the Power Production Business Unit and Purchased Power Agreements (PPAs) are functionalized to Generation.
- **Transmission & Distribution Business Unit:**
A small amount of the Transmission and Distribution Business Unit's OM&A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the OM&A expense for the Business Unit is split to transmission and distribution using cost centre reports.

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- Transmission OM&A is sub-functionalized by separating transmission OM&A expense into line and station-related functions. The line-related OM&A is sub-functionalized to main grid, 230 & 138 kV radials, & 72 kV radials using the transmission line assets plant in service by sub-function. The station-related OM&A expense is sub-functionalized using the station assets plant in service by sub-function.
 - Distribution OM&A is functionalized to distribution and customer services using a combination of staff input and detailed cost centre OM&A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions.
 - Metering Services OM&A was moved from Customer Services to Transmission & Distribution in 2013 but is still functionalized to Customer Services.
- **Customer Services Business Unit:**
The OM&A expense for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre OM&A reports.
 - **Customer Services - Bad Debt Expense:**
The Bad Debt expense is assigned to the customer collections sub-function within the Customer Services function.
 - **President / Board:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.
 - **Corporate & Financial Services:**
Functionalized based on employee head count by Business Unit and Support Group.
 - **Corporate & Financial Services – Insurance Premiums & Insurable Losses:**
Functionalized based on breakdown from SaskPower's risk management & insurance department staff.
 - **Asset Strategy & Planning:**
Asset Strategy & Planning was previously called Asset Management, Planning & Sustainability. It is made up of four cost centres: Generation Asset Management

and Supply Planning, Transmission Asset Management and Planning, Distribution Asset Management and Planning, and Environment. The Planning cost centres are assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Environment cost centre moved to Resource Planning from Human Resources in 2015 and is allocated based on an employee analysis which was done by SaskPower Environment department staff. The Shand Greenhouse is embedded within the Environment cost centre and is functionalized to Generation.

- **Carbon Capture & Storage (CCS):**
The OM&A expense for CCS is embedded within the Power Production business unit and is functionalized to Generation.
- **Small Modular Reactors (SMR) Consortium:**
The OM&A expense for SMR is embedded within the Asset Strategy & Planning business unit and is functionalized to Generation.
- **General Council / Land:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.
- **Safety:**
Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the OM&A sub-functionalization within each function.
- **Technology & Security (formerly Corporate Information & Technology):**
Technology & Security OM&A expense is separated into personal computer-related and Business Unit-related functions. The personal computer-related function is functionalized using employee headcount. The Business Unit-related function is functionalized using information from the cost centre report. Sub-functionalization is completed using OM&A within each function.
- **Human Resources:**
Functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function.
- **Commercial & Industrial Operations:**
Commercial & Industrial Operations is department made up of three cost centres: Coal Combustion Products, Fuel Supply and NorthPoint. The Customer Relations

cost centre was previously located here but has been since relocated back to Customer Services and continues to be functionalized to Customer Service. Coal Combustion, along with Individual Purchased Power cost centre was recently relocated to Finance but is being tracked and reported in the Power Production business unit and continues to be functionalized to Generation. The Fuel Supply cost centre was previously reported in Resource Planning and continues to be functionalized to Generation. NorthPoint previously was reported in Operations and continues to be functionalized to Generation.

- **Procurement & Supply Chain**

Procurement & Supply Chain is made up of three cost centres: Supply Chain, Properties & Shared Services, and Contract Management. Supply Chain and Properties & Shared Services are functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function. Contract Management is functionalized to Generation. The Logistics area was moved to Procurement & Supply Chain in 2015 from Distribution; however, based on Logistics' close relation to Distribution, their OM&A is still being calculated and functionalized within Distribution.

2.5 - Depreciation & Depletion

- The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.6 - Corporate Capital Tax

- Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.7 - Grants in Lieu of Taxes

- Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.8 – Miscellaneous Tax

- The miscellaneous tax expenses have been grouped into the following categories using cost centre reports:
 - **Power production-related:**
Functionalized to generation.
 - **Corporate-related:**
Functionalized using total OM&A expense.

2.9 - Other Income

- Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.
 - **Customer services payment income:**
Assigned to the billing, customer accounts and collections sub-functions within customer services.
 - **Meter reading income:**
Assigned to the meter reading sub-function within the customer services function.
 - **Transmission-related income:**
Assigned to sub-functions within the transmission function using transmission OM&A expense.
 - **Distribution-related income:**
Assigned to sub-functions within the distribution function using distribution OM&A expense.
 - **Miscellaneous Other Income:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.
 - **Customer Contribution Revenue**
As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.
 - **Green power premium:**
Assigned to the load and losses sub-functions within generation using fuel expense.
 - **Flyash & Wind Power Sales:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **CO2 Sales & Penalties:**
Assigned to the load and losses sub-functions within generation using fuel expense.
- **Renewable Energy Credits:**
Assigned to the load and losses sub-functions within generation using fuel expense.

2.10 - Return on Rate Base

- The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

STEP 3: CLASSIFICATION

The classification process splits the functionalized costs into the parameters of service, which are:

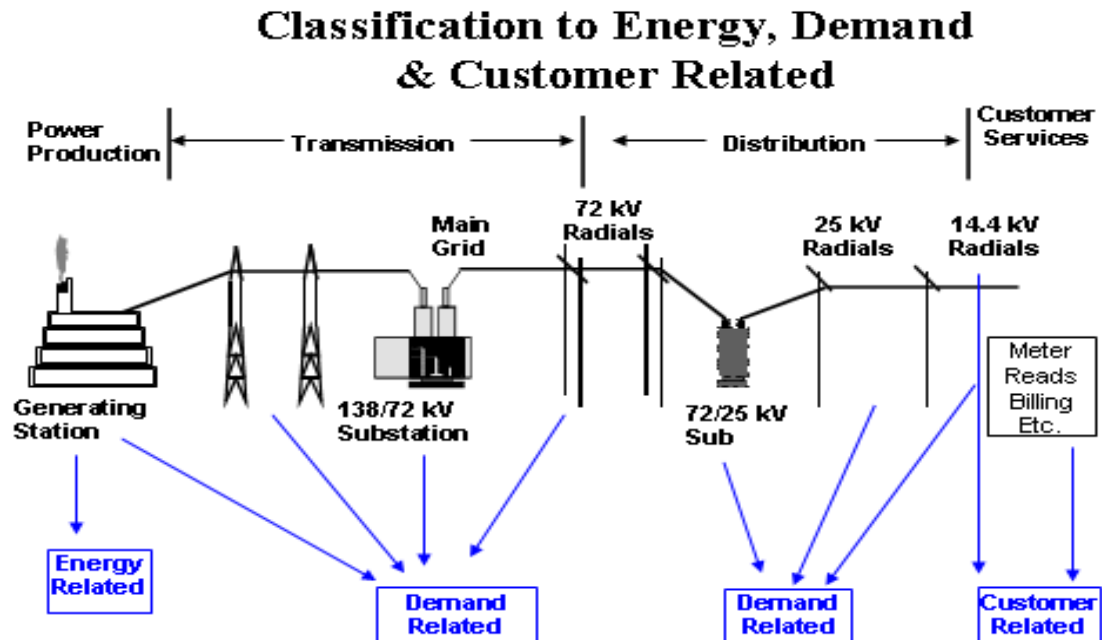
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission, and distribution systems.

Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.

Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

Figure 2 below presents a schematic of the classification process.

Figure 2: Classification Schematic



A discussion of the classification of each of the functionalized costs is as follows:

- **Generation:**

SaskPower generation rate base and expense is classified as either demand or energy-related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Average & Excess Demand method (AED), based on the NARUC Electric Utility Cost Allocation manual. The rationale behind AED is that a utility's average annual demand is required to meet its energy requirements, and any demand more than that average is required to meet its peaking requirements.

The assets and expenses associated with Purchased Power Agreements (PPAs) are classified to demand and energy using the capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation

operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The expenses and income associated with fly-ash sales (now called Coal Combustion Products) are classified as energy-related.

The classification of all wind generation rate base and expenses are also classified to energy and demand using the Average & Excess Demand method (AED). This is a change from previous years when SaskPower planning staff classified the wind units based on planning studies regarding the capacity value of wind generation.

Diesel units continue to be classified as 100% to demand.

- **Coal Reserves:**

SaskPower coal reserves are classified as energy-related.

- **Shand Greenhouse:**

The Shand Greenhouse assets, OM&A and depreciation expenses are classified using the classification of all SaskPower generation.

- **NorthPoint:**

The OM&A expense and other revenue associated with NorthPoint are classified 100% as energy-related.

- **Transmission:**

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% as demand-related.

- **Distribution:**

Substations are classified 100% as demand-related costs. Three phase feeders are classified 100% as demand-related costs.

Both urban and rural single-phase primary lines are classified 30% to demand-related and 70% to customer-related costs. Line transformers are classified 65% to demand-related and 35% to customer-related cost based upon Minimum System Method (MSM). As indicated in part D of the introduction, classification changes utilizing the MSM for urban and rural single-phase primary lines (laterals) and line transformers were recommended by the Elenchus Cost of Service Study in 2023 and implemented within this Cost of Service Study.

All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as a customer-related costs.

- **Customer:**
Customer costs are classified 100% as customer-related.

The results of the functionalization and classification (or functional classification) of rate base, expense, return on rate base, and revenue requirement are summarized in **Schedules 2.00 through to 2.36**.

STEP 4: ALLOCATION

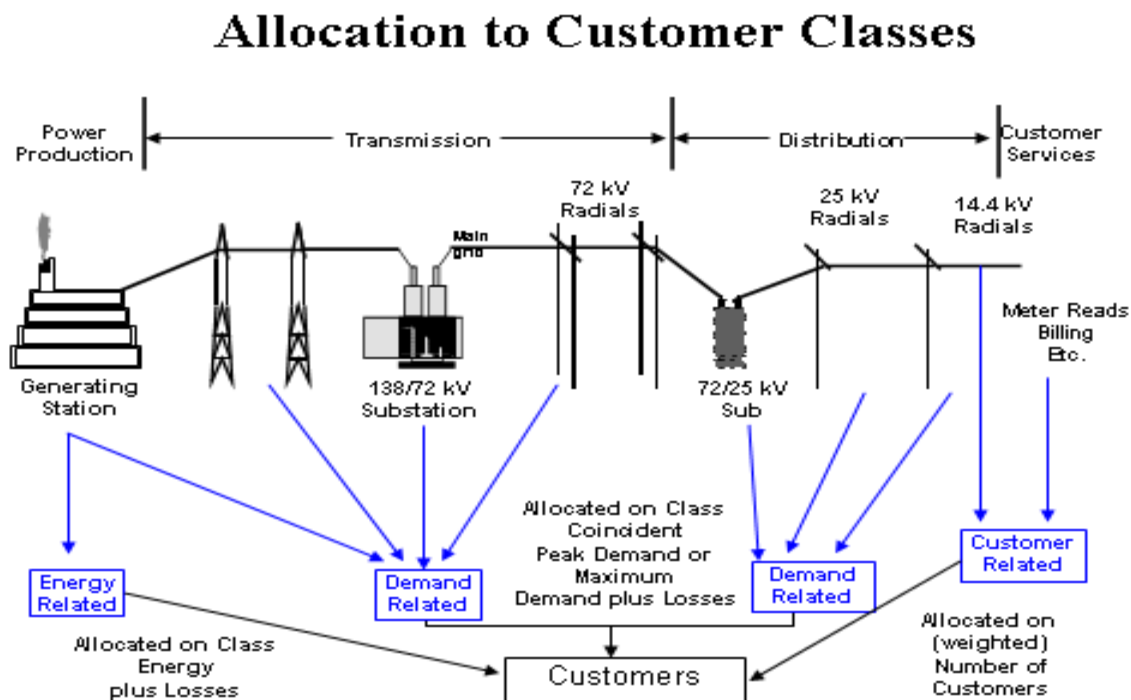
Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated:

- Residential
- Farms
- Commercial
- Power
- Oilfields
- Reseller

Figure 3 presents a schematic of the allocation process. The methodologies chosen by SaskPower for allocation are summarized in **Schedule 3.0**. The core data used in the development of allocation factors can be found in **Schedule 4.0**.

Figure 3: Allocation Schematic



An explanation of the allocation process by function is as follows:

- **Generation:**

The energy-related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand-related rate base and expenses are allocated by the Two Coincident Peak (2CP) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May, and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

- **Transmission:**

All transmission functions are classified as demand and are allocated using the 2CP method as aforementioned.

- **Distribution:**

The demand functions within distribution use a combination of the 2CP method and the Maximum Diversified Class Demands (MDD) method. The MDD method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demand of a rate class, regardless of when it occurs, during a specified period, to the sum of all the class peaks, similarly determined. Only the transformers' function uses the MDD methodology. All other functions use the 2CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight-related rate base and expenses are allocated directly to streetlights.

- **Customer Services:**

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

- **Customer Contributions:**

These contributions are allocated back directly to the customer classes which made the contribution.

- **Load Data:**

Customer load data is obtained for each class from the best available sources. Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The results for the customer types in each of these classes are then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.

Power class loads were analyzed based on hourly meter readings from actual customers' interval metered sites.

- **Loss Study:**

The purpose of a loss study is to properly quantify and assign the electrical energy and demand losses in the various segments of the system to the appropriate customer class. The starting point is the total energy loss in GWh, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

- **Allocators:**

The allocation factors are summarized in **Schedules 5.0 to 5.3**. The functionalization and classification of the revenue requirement is summarized in **Tables 1 and 2** (Summary of Results section), and the details are in **Schedules 6.0 to 6.3**.

STEP 5: COMPARE

The allocated rate base, allocated expenses, and class revenue are the foundation for calculating the revenue-to-revenue requirement (R/RR) ratio by class. A R/RR measure of 1.00 indicates that the revenues received from a customer class exactly matches the costs of providing it electrical service; or, to put it simply, a customer is paying the amount it costs SaskPower to provide them with service. An R/RR below 1.00 indicates that a customer class is paying less than the cost to serve while an R/RR above 1.00 indicates that a customer class is paying more than the cost to serve. On a system-wide basis, the ratio must equal 1.00.

In response to comments of cross-subsidization between SaskPower's customer classes, external consultants have advised SaskPower that R/RR ratios close to 1.00 are deemed to be reasonable. Cost allocation studies of shared assets utilized by various customer groups represents the best and most current information available but is subject to

fluctuations and uncertainty from year to year. A range of acceptable R/RR ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that a customer is paying their fair share of costs. As a result, a R/RR ratio that is slightly above or below 1.00 does not demonstrate that one customer class subsidizes or receives a subsidy from other customer classes if it falls within the acceptable range. In conclusion, if the R/RR ratios are within the acceptable range, the results are deemed to be reasonable and there is no refutable evidence of cross-subsidization.

R/RR ratios are determined by comparing the revenue collected from each class to the revenue required to serve the customer class. The revenue requirement for each customer class is calculated as the allocated rate base multiplied by the system return on rate base plus allocated expenses. Please refer to **Table 3** in the Summary of Results section for an R/RR ratio breakdown by customer class.

It is important to note that R/RR ratios are not static. Each year SaskPower rebuilds the cost of service model using the latest annual financial information and customer revenue and load data. As such, cost of service results will vary from year to year for several reasons, including:

- 1) Class Revenue Changes
- 2) Class Revenue Requirement Changes, due to:
 - Non-uniform escalation of generation, transmission, distribution & customer service costs (e.g., capital expenditures, fuel & purchased power, OM&A, and depreciation expense)
 - Changes to cost of service methodology
 - Changes to class demand (e.g., customer load factors) at system peak, due to:
 - Economic conditions
 - Mechanical failures
 - Unforeseen shutdowns
 - Operational changes
 - Variations in weather patterns

R/RR ratios in Base (actual) years are dependent on the actual annual revenue and the calculated revenue requirement derived from the Cost of Service Study which may reflect any, or all, of the above conditions.

In Test (forecast) years, SaskPower attempts to set the R/RR ratios between 0.98 to 1.02 using assumptions based on a “most likely” scenario, to stabilize rate designs and protect all customers from outlying or anomalous conditions that may occur. Maintaining this range is still the long-term goal, however due to the transition to a Conventional Rate

Design and the number of years since SaskPower's last rate rebalancing rate application, to avoid rate shock to certain rate classes, more discretion in the ratios had to be taken in this application.

STEP 6: DEVELOP "IDEAL" RATES

Each of SaskPower's customer classes is made up of one or more rate codes. A rate code outlines the specific price paid by a group of customers with similar characteristics. Separate rate codes may be required for size, the voltage level the customer is supplied at, or the type of load served (e.g., streetlights). SaskPower currently has 49 published rate codes.

As discussed above, one of the primary objectives of rate design is fairness and equity. To satisfy this objective, SaskPower designs rates to recover the appropriate amount of revenue from each rate code within a class. Rates are also designed to collect the appropriate revenue for an average-sized customer from their rate code within each class. Essentially this means if a class has a R/RR ratio of 1.01, then the rate will be designed such that the overall rate code and the average sized customer belonging to that rate code provides the same R/RR of 1.01.

Customer size is measured as the maximum customer demand in kW. Customer annual load factor is defined as:

Load factor = annual energy / (maximum demand * 8760 hours).

A high load factor customer has a steady load which does not vary much from hour to hour. Oilfield and Power customers typically have high load factors. A low load factor customer has high peak loads relative to the amount of energy consumed. Residential customers typically have low load factors.

The cost of service model provides the energy, demand, and customer-related revenue requirement for each class of customers (see **Table 2**), as well as for each rate code within a class. The energy, demand, and customer revenue requirement by rate code provides the basis for rate design.

Energy (Only) Metered Customers

All Residential, small Farm, and small Commercial customers have a simple energy meter. These meters cost much less than the demand & energy meter used for larger customers. The rate for energy metered customers includes an energy charge and a basic monthly charge. The combination of energy charge and basic monthly charge will collect the appropriate revenue from customers regardless of size. The energy charge and basic

monthly charge will not, however, collect the appropriate revenue for customers of all load factors. It will collect the appropriate revenue for customers at the average load factor for the rate code.

The energy charge is calculated as the energy plus demand revenue requirements divided by the rate code energy consumption. The basic monthly charge is calculated as the customer revenue requirement divided by the number of customer accounts in the rate code divided by 12 months.

Demand & Energy Metered Customers

Commercial and Farm customers over 50 kVA demand and all Power customers have a meter which measures both energy consumed in kWh and maximum monthly demand in kVA. The rates for demand & energy metered customers have separate charges for energy, demand, and the basic monthly charge. The combination of energy, demand and basic monthly charge is intended to collect the appropriate revenue for each customer regardless of size at the average load factor of the class.

SaskPower rates for demand & energy metered customers are designed using the cost of service model. Rates are designed by first determining the revenue requirement for a wide range of customer sizes and load factors. Then the rate is designed such that the appropriate revenue is collected for each combination of customer size at the average load factor of the class.

Once the energy only and the demand & energy rates are designed for all rate codes, they are tested in SaskPower's revenue model. This is done to ensure SaskPower collects the appropriate revenue overall (meets revenue requirements) and from each customer class (fairness and equity). A check is also made to ensure that no one customer receives more than the maximum allowable rate increase of 15%. The adjusted rates are finalized, approved by the Saskatchewan Rate Review Panel and Cabinet, and then published for each individual rate code.

IV. SUPPORTING SCHEDULES

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Rate Base and Expense Categories	SaskPower Total	Functional Breakdown					
		Generation	Transmission	Distribution	Customer Service		
Rate Base							
Plant In Service (Schedule 1.1)	22,129.2	11,474.6	3,945.6	17.8%	6,430.9	29.1%	278.2
Accumulated Depreciation (Schedule 1.2)	(9,909.4)	(5,940.6)	(1,337.3)	13.5%	(2,544.9)	25.7%	(86.6)
Allowance For Working Capital	129.8	74.0	17.2	13.2%	25.2	19.4%	13.4
Inventories (Schedule 1.3)	450.2	197.9	99.4	22.1%	153.0	34.0%	(0.2)
Other Assets (Schedule 1.3)	88.2	67.4	6.3	7.1%	9.2	10.4%	5.3
Total Rate Base	12,888.0	5,873.3	2,731.2	21.2%	4,073.3	31.6%	210.2
Revenue Requirement							
Fuel Expense SaskPower Units	589.4	589.4	-	0.0%	-	0.0%	-
Purchased Power & Import	258.5	258.5	-	0.0%	-	0.0%	-
Export & Net Electricity Trading Revenue (Credit)	(51.9)	(51.9)	-	0.0%	-	0.0%	-
Operating, Maintenance & Administration (Schedule 1.4)	932.9	525.1	122.4	13.1%	179.4	19.2%	106.0
Depreciation & Depletion (Schedule 1.5)	723.1	404.4	106.0	14.7%	200.9	27.8%	11.8
Corporate Capital Tax	70.0	31.7	14.9	21.3%	22.3	31.8%	1.1
Grants in Lieu of Taxes	34.4	34.4	-	0.0%	-	0.0%	-
Miscellaneous Tax	1.0	1.0	-	0.0%	-	0.0%	-
Other Income (Credit) (Schedule 1.6)	(132.1)	(30.3)	(24.2)	18.3%	(67.1)	50.8%	(10.5)
Return on Rate Base @ 4.59%	591.1	269.4	125.3	21.2%	186.8	31.6%	9.6
Total Revenue Requirement	3,016.4	2,031.7	344.3	11.4%	522.3	17.3%	118.0

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details PLANT IN SERVICE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)								
Asset Categories	SaskPower Total	Functional Breakdown						
		Generation		Transmission		Distribution		Customer Service
Generation Assets								
Power Production	9,631.8	9,631.8	100.0%	-	0.0%	-	0.0%	-
Power Production - PPA	1,218.4	1,218.4	100.0%	-	0.0%	-	0.0%	-
Coal Reserves	75.0	75.0	100.0%	-	0.0%	-	0.0%	-
Shand Greenhouse	6.0	6.0	100.0%	-	0.0%	-	0.0%	-
Total Generation Assets	10,931.2	10,931.2	100.0%	-	0.0%	-	0.0%	0.0%
Transmission Assets								
Transmission Assets	3,592.9	7.4	0.2%	3,549.4	98.8%	36.1	1.0%	-
Total Transmission Assets	3,592.9	7.4	0.2%	3,549.4	98.8%	36.1	1.0%	0.0%
Distribution Assets								
Distribution Assets	5,809.9	-	0.0%	-	0.0%	5,809.9	100.0%	-
Meters	132.5	-	0.0%	-	0.0%	132.5	100.0%	-
Instrument Transformers	22.7	-	0.0%	-	0.0%	22.7	100.0%	-
Total Distribution Assets	5,965.1	-	0.0%	-	0.0%	5,965.1	100.0%	0.0%
General Plant Assets								
Unused Land	2.3	1.3	56.3%	0.3	13.1%	0.4	19.2%	0.3
Right of Use Land	10.3	5.8	56.3%	1.3	13.1%	2.0	19.2%	1.2
Buildings	720.0	209.3	29.1%	141.7	19.7%	189.1	26.3%	180.0
Right of Use Buildings	7.9	2.1	26.5%	1.6	20.5%	2.1	27.3%	2.0
Office Furniture & Equipment	62.9	18.3	29.1%	12.4	19.7%	16.5	26.3%	15.7
Vehicles & Equipment	259.9	38.1	14.7%	86.3	33.2%	113.8	43.8%	21.6
Computer Development & Equipment	404.9	208.5	51.5%	62.2	15.3%	80.2	19.8%	54.1
Communication, Protection & Control	144.8	45.0	31.1%	81.1	56.0%	16.5	11.4%	2.2
Tools & Equipment	27.0	7.7	28.6%	9.2	34.0%	9.0	33.2%	1.1
Total General Plant Assets	1,640.0	536.0	32.7%	396.1	24.2%	429.7	26.2%	278.2
Total Plant in Service	22,129.2	11,474.6	51.9%	3,945.6	17.8%	6,430.9	29.1%	278.2
								1.3%

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details ACCUMULATED DEPRECIATION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)						
Asset Categories	SaskPower Total	Functional Breakdown				
		Generation	Transmission	Distribution	Customer Service	
Generation Assets						
Power Production	(4,906.6)	100.0%	-	0.0%	-	0.0%
Power Production - PPA	(718.4)	100.0%	-	0.0%	-	0.0%
Coal Reserves	(53.0)	100.0%	-	0.0%	-	0.0%
Shand Greenhouse	(4.5)	100.0%	-	0.0%	-	0.0%
Total Generation Assets	(5,682.4)	100.0%	-	0.0%	-	0.0%
Transmission Assets						
Transmission Assets	(1,169.5)	0.2%	(1,147.9)	98.2%	(19.8)	1.7%
Total Transmission Assets	(1,169.5)	0.2%	(1,147.9)	98.2%	(19.8)	1.7%
Distribution Assets						
Distribution Assets	(2,256.7)	0.0%	-	0.0%	(2,256.7)	100.0%
Meters	(71.1)	0.0%	-	0.0%	(71.1)	100.0%
Instrument Transformers	(16.4)	0.0%	-	0.0%	(16.4)	100.0%
Total Distribution Assets	(2,344.2)	0.0%	-	0.0%	(2,344.2)	100.0%
General Plant Assets						
Unused Land	-	0.0%	-	0.0%	-	0.0%
Right of Use Land	(4.5)	56.3%	(0.6)	13.1%	(0.9)	19.2%
Buildings	(92.7)	(31.4)	(17.1)	18.4%	(22.8)	24.6%
Right of Use Buildings	(6.0)	(1.6)	(1.2)	20.5%	(1.6)	27.3%
Office Furniture & Equipment	(34.7)	(11.7)	(6.4)	18.4%	(8.5)	24.6%
Vehicles & Equipment	(151.6)	(20.4)	(51.0)	33.7%	(67.3)	44.4%
Computer Development & Equipment	(299.0)	(149.9)	(47.6)	15.9%	(61.7)	20.6%
Communication, Protection & Control	(106.5)	(33.6)	(58.6)	55.0%	(12.6)	11.8%
Tools & Equipment	(18.2)	(5.1)	(6.9)	37.7%	(5.6)	30.5%
Total General Plant Assets	(713.3)	(256.3)	(189.4)	26.6%	(181.0)	25.4%
Total Accumulated Depreciation	(9,909.4)	(5,940.6)	(1,337.3)	13.5%	(2,544.9)	25.7%
					(86.6)	12.1%
					(86.6)	0.9%

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details INVENTORIES 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)					

	SaskPower Total	Functional Breakdown			
		Generation	Transmission	Distribution	Customer Service
Inventories					
Power Production - Repair Stores	145.6	100.0%	-	0.0%	0.0%
Power Production - Fuel	53.1	100.0%	-	0.0%	0.0%
Transmission & Distribution	252.9	0.0%	99.6	153.3	0.0%
Miscellaneous (Computers, Power Shop)	(1.4)	56.3%	(0.2)	(0.3)	-
Total Inventories	450.2	44.0%	99.4	153.0	11.4%

Functionalization of Financial Account Details OTHER ASSETS 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)					

	SaskPower Total	Functional Breakdown			
		Generation	Transmission	Distribution	Customer Service
Other Assets					
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	100.0%	-	0.0%	0.0%
Intangible Assets	-	0.0%	-	0.0%	0.0%
Prepaid Expenses - Insurance	5.8	90.0%	0.2	0.3	0.0
Miscellaneous Prepaid Expenses	46.2	56.3%	6.1	8.9	5.2
Total Generation Expenses	88.2	76.5%	6.3	9.2	5.3

Schedule 1.4: Functionalization of Financial Account Details – OM&A Expense

Functionalization of Financial Account Details OM&A EXPENSES 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	303.1	303.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	40.9	40.9	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchase Power Agreements (PPA)	18.5	18.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	362.5	362.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution Expenses									
Planning Support	24.0	13.0	54.3%	10.6	44.2%	0.1	0.4%	0.3	1.1%
Transmission Including 230/138 & 72 kV Radials	66.7	-	0.0%	66.7	100.0%	-	0.0%	-	0.0%
Distribution	118.9	-	0.0%	-	0.0%	118.9	100.0%	-	0.0%
Customer Services	8.7	-	0.0%	-	0.0%	-	0.0%	8.7	100.0%
Metering Services	5.5	-	0.0%	-	0.0%	-	0.0%	5.5	100.0%
Total Transmission & Distribution Expenses	223.8	13.0	5.8%	77.3	34.5%	119.0	53.2%	14.5	6.5%
Customer Services Expenses									
Meter Reading	14.7	-	0.0%	-	0.0%	-	0.0%	14.7	100.0%
Billing Services	4.0	-	0.0%	-	0.0%	-	0.0%	4.0	100.0%
Collections/Special Collections	2.0	-	0.0%	-	0.0%	-	0.0%	2.0	100.0%
Bad Debt Expense	10.3	-	0.0%	-	0.0%	-	0.0%	10.3	100.0%
Marketing & Sales	3.2	-	0.0%	-	0.0%	-	0.0%	3.2	100.0%
Demand Side Management	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	26.5	-	0.0%	-	0.0%	-	0.0%	26.5	100.0%
Total Customer Services Expenses	60.7	-	0.0%	-	0.0%	-	0.0%	60.7	100.0%
Support Group Expenses									
President / Board	2.5	1.4	56.3%	0.3	13.1%	0.5	19.2%	0.3	11.4%
Corporate & Financial Services (C&FS)	12.0	5.2	43.1%	2.2	18.4%	2.9	24.6%	1.7	13.8%
C&FS - Insurance Premiums & Insurable Losses	20.4	18.3	90.0%	0.8	4.0%	1.1	5.3%	0.1	0.6%
Asset Management, Planning, & Sustainability	28.5	14.6	51.3%	5.2	18.1%	6.9	24.2%	1.8	6.5%
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
SMR Consortium	7.4	7.4	100.0%	-	0.0%	-	0.0%	-	0.0%
General Council / Land	5.5	3.1	56.3%	0.7	13.1%	1.1	19.2%	0.6	11.4%
Safety	7.6	3.8	49.3%	1.3	16.9%	1.8	23.3%	0.8	10.4%
Corporate Information & Technology	111.8	51.1	45.7%	19.4	17.4%	25.7	23.0%	15.6	13.9%
Human Resources	36.2	14.2	39.2%	7.6	20.9%	10.3	28.4%	4.2	11.6%
Commercial & Industrial Operations	12.8	12.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Procurement & Supply Chain	41.4	17.8	43.1%	7.6	18.4%	10.2	24.6%	5.7	13.8%
Total Support Group Expenses	286.0	149.6	52.3%	45.1	15.8%	60.4	21.1%	30.8	10.8%
Total OM&A Expenses	932.9	525.1	56.3%	122.4	13.1%	179.4	19.2%	106.0	11.4%

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details DEPRECIATION & DEPLETION EXPENSE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Functional Breakdown					
		Generation	Transmission	Distribution	Customer Service		
Generation Assets							
Power Production	320.5	320.5	-	-	0.0%	-	0.0%
Purchase Power Agreements (PPA)	54.5	54.5	-	-	0.0%	-	0.0%
Coal Reserves	3.0	3.0	-	-	0.0%	-	0.0%
Shand Greenhouse	0.2	0.2	-	-	0.0%	-	0.0%
Total Generation Assets	378.1	378.1	0.0%	0.0%	0.0%	-	0.0%
Transmission Assets							
Transmission Assets	89.6	0.1	88.4	1.0	1.1%	-	0.0%
Total Transmission Assets	89.6	0.1	88.4	1.0	1.1%	-	0.0%
Distribution Assets							
Distribution Assets	169.7	-	-	169.7	100.0%	-	0.0%
Meters	7.7	-	-	7.7	100.0%	-	0.0%
Instrument Transformers	1.3	-	-	1.3	100.0%	-	0.0%
Total Distribution Assets	178.7	-	0.0%	178.7	100.0%	-	0.0%
General Plant Assets							
Unused Land	(0.0)	(0.0)	(0.0)	(0.0)	19.2%	(0.0)	11.4%
Right of Use Land	0.7	0.4	0.1	0.1	19.2%	0.1	11.4%
Buildings	15.3	4.2	3.1	4.1	27.0%	3.9	25.5%
Right of Use Buildings	1.9	0.5	0.4	0.5	27.3%	0.5	25.7%
Office Furniture & Equipment	3.6	1.0	0.7	1.0	27.0%	0.9	25.5%
Vehicles & Equipment	13.1	1.5	4.5	5.9	45.1%	1.2	9.2%
Computer Development & Equipment	36.8	16.9	6.4	8.4	22.9%	5.1	13.9%
Communication, Protection & Control	2.5	0.7	1.5	0.2	10.0%	0.0	1.4%
Tools & Equipment	2.8	1.0	0.9	0.8	28.7%	0.1	3.5%
Total General Plant Assets	76.7	26.2	17.5	21.1	27.6%	11.8	15.4%
Total Depreciation Expense	723.1	404.4	106.0	200.9	27.8%	11.8	1.6%

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details OTHER INCOME 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)						
Expense Categories	SaskPower Total	Functional Breakdown				
		Generation	Transmission	Distribution	Customer Service	
Other Income						
Customer Services Payment Charges	(8.0)	-	-	-	(8.0)	100.0%
Meter Reading	(2.2)	-	-	-	(2.2)	100.0%
Transmission	(3.8)	(0.5)	(3.3)	-	-	0.0%
Distribution	(7.5)	-	-	(7.5)	-	0.0%
Miscellaneous Other Income	(2.7)	(1.5)	(0.4)	(0.5)	(0.3)	11.4%
Customer Contribution Revenue	(79.7)	-	(20.6)	(59.1)	-	0.0%
Green Power Premium	(0.0)	(0.0)	-	-	-	0.0%
Flyash Sales	(10.7)	(10.7)	-	-	-	0.0%
CO2 Sales & Penalties	(16.7)	(16.7)	-	-	-	0.0%
Renewable Energy Credits	(0.8)	(0.8)	-	-	-	0.0%
Total Other Income	(132.1)	(30.3)	(24.2)	(67.1)	(10.5)	7.9%

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalization and Classification of Financial Account Details																	
GENERATION Related Costs																	
2026 Fiscal Test Embedded Cost of Service Study																	
(\$ Millions)																	
Rate Base and Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve	Reactive Supply		Grants in Lieu of Taxes
					Demand	Energy	Demand	Energy			Demand	Energy			Demand	Energy	
Rate Base																	
Plant In Service (Schedule 2.01)	22,129.2	11,474.6	51.9%	Functional Class of PIS	1,897.3	7,424.5	218.7	517.6	33.9	84.7	253.8	380.7	475.2	198.2	-	-	-
Accumulated Depreciation (Schedule 2.02)	(9,909.4)	(5,940.6)	59.9%	Functional Class of Accum. Dep'n	(1,090.8)	(3,842.0)	(126.4)	(267.9)	(24.4)	(39.6)	(106.3)	(159.4)	(199.0)	(84.9)	-	-	-
Allowance for Working Capital	129.8	74.0	57.0%	12.50% of OMA& and Taxes	31.2	25.5	3.6	1.8	1.6	0.6	2.2	1.6	2.0	1.0	4.3	-	-
Inventories (Schedule 2.03)	450.2	197.9	44.0%	Functional Class of Inventories	73.5	96.5	8.5	6.7	(0.0)	0.6	2.2	3.4	4.2	2.2	-	-	-
Other Assets (Schedule 2.03)	88.2	67.4	76.5%	Functional Classification of Other Assets	14.6	44.6	1.7	3.1	14.7	0.6	0.5	0.7	0.9	0.5	-	-	-
Total Rate Base	12,888.0	5,873.3	46.6%		915.9	3,749.2	106.1	261.4	11.7	46.3	151.3	226.9	283.3	117.0	4.3	-	-
Revenue Requirement																	
Fuel Expense SaskPower Units	589.4	589.4	100.0%	Functional Class of Fuel Exp.	-	550.9	-	38.4	-	-	-	-	-	-	0.1	-	-
Purchased Power & Import	258.5	258.5	100.0%	Functional Class of PP, Import & NP Fee	68.2	170.5	7.9	11.9	-	-	-	-	-	-	0.0	-	-
Export & Net Electricity Trading Revenue (Credit)	(51.9)	(51.9)	100.0%	Functional Class of Exports	-	(48.5)	-	(3.4)	-	-	-	-	-	-	(0.0)	-	-
Operating, Maintenance & Administration (Schedule 2.04)	932.9	525.1	56.3%	Functional Class of OMA&	244.5	383.0	28.3	12.8	12.5	3.2	7.6	11.4	14.3	7.5	-	-	-
Depreciation & Depletion (Schedule 2.05)	723.1	404.4	55.9%	Functional Class of Dep'n & Depletion	72.1	254.7	8.4	17.8	0.6	2.9	9.4	14.0	17.5	7.2	-	-	-
Corporate Capital Tax	70.0	31.7	45.3%	Functional Class of Corp. Capital Tax	4.6	20.5	0.5	1.4	0.1	0.3	0.8	1.3	1.6	0.6	-	-	-
Grants in Lieu of Taxes	34.4	34.4	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	34.4	-	-
Miscellaneous Tax	1.0	1.0	100.0%	Functional Class of Misc. Tax	0.5	0.3	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-	-	-
Other Income (Credit) (Schedule 2.06)	(132.1)	(132.1)	23.0%	Functional Class of Other Income	(0.7)	(27.0)	(0.1)	(1.9)	(0.5)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	-
Return on Rate Base @ 4.59%	591.1	269.4	45.6%	Rate Base	42.0	172.0	4.9	12.0	0.5	2.1	6.9	10.4	13.0	5.4	-	-	-
Total Revenue Requirement	3,016.4	2,031.7	67.4%		431.1	1,276.5	50.0	89.0	13.2	8.4	24.8	37.1	46.4	26.7	34.6	-	-

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Functionalization and Classification of Financial Account Details GENERATION PLANT IN SERVICE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)																		
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes			
				Demand	Energy						Demand	Energy				Demand	Energy	
Generation Assets																		
Power Production	9,631.8	9,631.8	100.0%	1,091.8	6,752.7	126.5	470.8	-	62.1	219.1	328.6	410.3	169.9	-	-			
Power Production - PPA	1,218.4	1,218.4	100.0%	559.5	414.8	64.8	28.9	-	7.9	27.7	41.6	51.9	21.4	-	-			
Coal Reserves	75.0	75.0	100.0%	-	70.1	-	4.9	-	-	-	-	-	0.0	-	-			
Shand Greenhouse	6.0	6.0	100.0%	0.8	4.8	0.1	0.3	-	-	-	-	-	-	-	-			
Total Generation Assets	10,931.2	10,931.2	100.0%	1,652.0	7,242.4	191.4	505.0	-	69.9	246.8	370.2	462.2	191.4	-	-			
Transmission Assets																		
Transmission Assets	3,592.9	7.4	0.2%	6.6	-	0.8	-	-	-	-	-	-	-	-	-			
Total Transmission Assets	3,592.9	7.4	0.2%	6.6	-	0.8	-	-	-	-	-	-	-	-	-			
Distribution Assets																		
Distribution Assets	5,809.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-			
Meters	132.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-			
Instrument Transformers	22.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-			
Total Distribution Assets	5,965.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
General Plant Assets																		
Unused Land	2.3	1.3	56.3%	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-			
Right of Use Land	10.3	5.8	56.3%	2.7	2.0	0.3	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	-			
Buildings	720.0	209.3	29.1%	87.5	88.5	10.1	6.2	1.6	0.9	2.7	4.0	5.0	2.6	2.6	-			
Right of Use Buildings	7.9	2.1	26.5%	0.8	0.9	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-			
Office Furniture & Equipment	62.9	18.3	29.1%	7.6	7.7	0.9	0.5	0.1	0.1	0.2	0.4	0.4	0.2	0.2	-			
Vehicles & Equipment	259.9	38.1	14.7%	19.3	12.4	2.2	0.9	0.0	0.2	0.6	0.9	1.1	0.6	0.6	-			
Computer Development & Equipment	404.9	208.5	51.5%	106.2	67.5	12.3	4.7	(0.6)	1.0	3.2	4.8	6.0	3.2	3.2	-			
Communication, Protection & Control	144.8	45.0	31.1%	-	-	-	-	32.5	12.5	-	-	-	-	-	-			
Tools & Equipment	27.0	7.7	28.6%	3.9	2.5	0.5	0.2	-	0.0	0.1	0.2	0.2	0.1	0.1	-			
Total General Plant Assets	1,640.0	536.0	32.7%	228.7	182.1	26.5	12.7	33.9	14.8	7.0	10.5	13.1	6.8	6.8	-			
Total Plant in Service	22,129.2	11,474.6	51.9%	1,887.3	7,424.5	218.7	517.6	33.9	84.7	253.8	380.7	475.2	198.2	198.2	-			

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details GENERATION ACCUMULATED DEPRECIATION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)																				
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Load	Losses		Losses	Scheduling & Dispatch	Regulation & Frequency Response		Spinning Reserve	Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes		
				Demand	Energy		Demand	Energy			Demand	Energy		Demand	Energy				Demand	Energy
Generation Assets																				
Power Production	(4,906.6)	(4,906.6)	100.0%	(661.6)	(3,439.4)		(76.6)	(239.8)		-	(25.4)	(89.8)		(134.7)	(168.1)		(71.2)	-		
Power Production - PPA	(718.4)	(718.4)	100.0%	(317.3)	(273.6)		(36.8)	(19.1)		-	(3.7)	(13.1)		(19.7)	(24.6)		(10.4)	-		
Coal Reserves	(53.0)	(53.0)	100.0%	-	(49.5)		-	(3.5)		-	-	-		-	-		(0.0)	-		
Shard Greenhouse	(4.5)	(4.5)	100.0%	(0.7)	(3.5)		(0.1)	(0.2)		-	-	-		-	-		-	-		
Total Generation Assets	(5,682.4)	(5,682.4)	100.0%	(979.6)	(3,766.0)		(113.5)	(262.6)		-	(29.2)	(102.9)		(154.4)	(192.7)		(81.6)	-		
Transmission Assets																				
Transmission Assets	(1,169.5)	(1.8)	0.2%	(1.6)	-		(0.2)	-		-	-	-		-	-		-	-		
Total Transmission Assets	(1,169.5)	(1.8)	0.2%	(1.6)	-		(0.2)	-		-	-	-		-	-		-	-		
Distribution Assets																				
Distribution Assets	(2,256.7)	-	0.0%	-	-		-	-		-	-	-		-	-		-	-		
Meters	(71.1)	-	0.0%	-	-		-	-		-	-	-		-	-		-	-		
Instrument Transformers	(16.4)	-	0.0%	-	-		-	-		-	-	-		-	-		-	-		
Total Distribution Assets	(2,344.2)	-	0.0%	-	-		-	-		-	-	-		-	-		-	-		
General Plant Assets																				
General Plant Assets	-	-	0.0%	-	-		-	-		-	-	-		-	-		-	-		
Right of Use Land	(4.5)	(2.5)	56.3%	(1.2)	(0.9)		(0.1)	(0.1)		(0.1)	(0.0)	(0.0)		(0.1)	(0.1)		(0.0)	-		
Buildings	(92.7)	(31.4)	33.9%	(13.7)	(12.6)		(1.6)	(0.9)		(0.2)	(0.1)	(0.4)		(0.6)	(0.8)		(0.4)	-		
Right of Use Buildings	(6.0)	(1.6)	26.5%	(0.6)	(0.7)		(0.1)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)	(0.0)		(0.0)	-		
Office Furniture & Equipment	(34.7)	(11.7)	33.9%	(5.1)	(4.7)		(0.6)	(0.3)		(0.1)	(0.1)	(0.2)		(0.2)	(0.3)		(0.2)	-		
Vehicles & Equipment	(151.6)	(20.4)	13.5%	(10.3)	(6.7)		(1.2)	(0.5)		(0.1)	(0.1)	(0.3)		(0.5)	(0.6)		(0.3)	-		
Computer Development & Equipment	(299.0)	(149.9)	50.1%	(76.0)	(48.8)		(8.8)	(3.4)		0.2	(0.8)	(2.3)		(3.5)	(4.3)		(2.3)	-		
Communication, Protection & Control	(106.5)	(33.6)	31.6%	-	-		-	-		(24.3)	(9.3)	-		-	-		-	-		
Tools & Equipment	(18.2)	(5.1)	28.0%	(2.6)	(1.7)		(0.3)	(0.1)		-	(0.0)	(0.1)		(0.1)	(0.1)		(0.1)	-		
Total General Plant Assets	(713.3)	(256.3)	35.9%	(109.6)	(76.0)		(12.7)	(5.3)		(24.4)	(10.5)	(3.3)		(5.0)	(6.3)		(3.3)	-		
Total Accumulated Depreciation	(9,509.4)	(5,940.6)	59.9%	(1,090.8)	(3,842.0)		(126.4)	(267.9)		(24.4)	(39.6)	(106.3)		(159.4)	(199.0)		(84.9)	-		

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details																	
GENERATION INVENTORIES																	
2026 Fiscal Test Embedded Cost of Service Study																	
(\$ Millions)																	
Asset Categories	SakPower Total	Generation Total	Generation as a % of SakPower Total	Load		Losses		Losses	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy		Demand	Energy		Demand	Energy				
Inventories																	
Power Production - Repair Stores	145.6	145.6	100.0%	73.9	47.2	8.6	3.3	-	-	0.6	2.3	-	3.4	4.2	2.2	-	-
Power Production - Fuel	53.1	53.1	100.0%	-	49.6	-	3.5	-	-	-	-	-	-	-	0.0	-	-
Transmission & Distribution	252.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	(1.4)	(0.8)	56.3%	(0.4)	(0.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Total Inventories	450.2	197.9	44.0%	73.5	96.5	8.5	6.7	(0.0)	(0.0)	0.6	2.2	-	3.4	4.2	2.2	-	-

Functionalization and Classification of Financial Account Details																			
GENERATION OTHER ASSETS																			
2026 Fiscal Test Embedded Cost of Service Study																			
(\$ millions)																			
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Losses	Scheduling & Dispatch		Regulation & Frequency Response		Spinning Reserve		Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy		Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy			
Other Assets																			
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	36.3	100.0%	-	33.9	-	2.4	-	-	-	-	-	-	-	-	-	-	0.0	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	5.2	90.0%	2.6	1.7	0.3	0.1	0.3	-	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	-
Miscellaneous Prepaid Expenses	46.2	26.0	56.3%	12.1	9.1	1.4	0.6	0.6	0.6	0.6	0.2	0.4	0.4	0.6	0.6	0.7	0.4	0.4	-
Total Other Assets	88.2	67.4	76.5%	14.7	44.6	1.7	3.1	3.1	0.6	0.6	0.2	0.5	0.5	0.7	0.9	0.5	0.5	-	-

Schedule 2.04: Functional Classification of Financial Account Details – Generation OM&A Expenses

Functionalization and Classification of Financial Account Details																
GENERATION OM&A EXPENSES																
2026 Fiscal Test Embedded Cost of Service Study																
(\$ millions)																
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses	Losses	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy			Demand	Energy			Demand	Energy			
Generation Expenses	303.1	303.1	100.0%	153.8	98.2	17.8	6.8	-	-	1.3	4.7	7.0	8.8	4.6	-	-
Power Plant Operation	40.9	40.9	100.0%	20.7	13.2	2.4	0.9	-	-	0.2	0.6	0.9	1.2	0.6	-	-
Power Production Overhead	18.5	18.5	100.0%	4.2	11.4	0.5	0.8	-	-	0.1	0.3	0.4	0.5	0.3	-	-
Purchase Power Agreements (PPA)	362.5	362.5	100.0%	178.7	122.9	20.7	8.6	-	-	1.6	5.6	8.4	10.5	5.5	-	-
Total Generation Expenses																
Transmission & Distribution Expenses																
Planning Support	24.0	13.0	54.3%	0.0	0.2	0.0	0.0	11.8	1.0	-	-	-	-	-	-	-
Transmission Including 230/138 & 72 kV Radials	66.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	118.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Services	8.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Metering Services	5.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	223.8	13.0	5.8%	0.0	0.2	0.0	0.0	11.8	1.0	-	-	-	-	-	-	-
Customer Services Expenses																
Meter Reading	14.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Services	4.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	2.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	10.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	3.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	26.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	60.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
Support Group Expenses																
President / Board	2.5	1.4	56.3%	0.7	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-
Corporate & Financial Services (C&FS)	12.0	5.2	43.1%	2.3	2.0	0.3	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	-	-
C&FS- Insurance Premiums & Insurable Losses	20.4	18.3	90.0%	9.3	5.9	1.1	0.4	-	-	0.1	0.3	0.4	0.5	0.3	-	-
Asset Management, Planning, & Sustainability	28.5	14.6	51.3%	4.5	8.2	0.5	0.6	0.1	0.0	0.0	0.1	0.2	0.3	0.1	-	-
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR Consortium	7.4	7.4	100.0%	3.8	2.4	0.4	0.2	-	-	0.0	0.1	0.2	0.2	0.1	-	-
General Council / Land	5.5	3.1	56.3%	1.4	1.1	0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0	-	-
Safety	7.6	3.8	49.3%	1.8	1.3	0.2	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.1	-	-
Corporate Information & Technology	111.8	51.1	45.7%	25.0	17.6	2.9	1.2	0.1	0.0	0.2	0.8	1.1	1.4	0.7	-	-
Human Resources	36.2	14.2	39.2%	6.5	5.2	0.8	0.4	0.2	0.1	0.2	0.4	0.3	0.4	0.2	-	-
Commercial & Industrial Operations	12.8	12.8	100.0%	2.3	9.2	0.3	0.6	-	-	0.0	0.1	0.1	0.1	0.1	-	-
Procurement & Supply Chain	41.4	17.8	43.1%	8.1	6.8	0.9	0.5	-	-	0.1	0.2	0.4	0.5	0.2	-	-
Total Support Group Expenses	286.0	149.6	52.3%	65.7	60.0	7.6	4.2	0.7	0.6	2.0	3.0	3.8	4.3	2.0	-	-
Total OM&A Expenses	932.9	525.1	56.3%	244.5	183.0	28.3	12.8	12.5	3.2	7.6	11.4	14.3	7.5	-	-	-

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details GENERATION DEPRECIATION & DEPLETION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)															
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve		Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy				Demand	Energy			
Generation Assets															Energy
Power Production	320.5	320.5	100.0%	34.6	224.6	4.0	15.7	-	2.2	7.7	11.5	14.4	5.8	-	-
Purchase Power Agreements (PPA)	54.5	54.5	100.0%	25.3	17.9	2.9	1.3	-	0.4	1.3	2.0	2.4	1.0	-	-
Coal Reserves	3.0	3.0	100.0%	-	2.8	-	0.2	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	0.2	100.0%	0.0	0.2	0.0	0.0	-	-	-	-	-	-	-	-
Total Generation Assets	378.1	378.1	100.0%	59.9	245.5	6.9	17.1	-	2.5	9.0	13.5	16.8	6.8	-	-
Transmission Assets															
Transmission Assets	89.6	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-	-
Total Transmission Assets	89.6	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-	-
Distribution Assets															
Distribution Assets	169.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Instrument Transformers	1.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	178.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
General Plant Assets															
General Plant Assets	(0.0)	(0.0)	56.3%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	-
Unused Land	0.7	0.4	56.3%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-
Right of Use Land	15.3	4.2	27.3%	1.7	1.8	0.2	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-	-
Buildings	1.9	0.5	26.5%	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-
Right of Use Buildings	3.6	1.0	27.3%	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-
Office Furniture & Equipment	13.1	1.5	11.5%	0.8	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-
Vehicles & Equipment	36.8	16.9	45.9%	8.3	5.8	1.0	0.4	0.0	0.1	0.3	0.4	0.5	0.2	-	-
Computer Development & Equipment	2.5	0.7	28.3%	-	-	-	-	0.5	0.2	-	-	-	-	-	-
Communication, Protection & Control	2.8	1.0	36.0%	0.5	0.3	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-	-
Tools & Equipment	76.7	26.2	34.2%	12.1	9.2	1.4	0.6	0.6	0.3	0.4	0.6	0.7	0.4	-	-
Total General Plant Assets	723.1	404.4	55.9%	72.1	254.7	8.4	17.8	0.6	2.9	9.4	14.0	17.5	7.2	-	-
Total Depreciation & Depletion															

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details														
GENERATION OTHER INCOME														
2026 Fiscal Year Estimated Cost of Service Study														
(\$ millions)														
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Demand
Other Income														
Customer Services Payment Charges	(8.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission	(3.8)	(0.5)	14.2%	-	-	-	-	(0.5)	(0.0)	-	-	-	-	-
Distribution	(1.7)	(1.5)	56.3%	(0.7)	(0.5)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Miscellaneous Other Income	(75.7)	(0.0)	0.0%	-	-	-	-	-	-	-	-	-	-	-
Customer Contributions Revenue	(60.0)	(0.0)	100.0%	-	(0.0)	(0.0)	(0.0)	-	-	-	-	-	(0.0)	-
Goodwill Premium	(10.7)	(10.7)	100.0%	-	(10.0)	-	-	-	-	-	-	-	(0.0)	-
Flash Sales	(16.7)	(16.7)	100.0%	-	(15.6)	-	-	(1.1)	-	-	-	-	(0.0)	-
CO2 Sales & Penalties	(0.8)	(0.8)	100.0%	-	(0.7)	-	-	(0.1)	-	-	-	-	(0.0)	-
Renewable Energy Credits														
Total Other Income	(132.1)	(30.3)	23.0%	(0.7)	(27.0)	(0.1)	(0.1)	(1.9)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	-

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details TRANSMISSION Related Costs 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)												
Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid		230kV & 138kV Radials		138/72 kV Substations		72 kV Lines Radials	
					Demand		Demand		Demand		Demand	
Rate Base												
Plant in Service (Schedule 2.11)	22,129.2	3,945.6	17.8%	Functional Class of PIS	2,426.4	906.7	198.7	413.9				
Accumulated Depreciation (Schedule 2.12)	(9,909.4)	(1,337.3)	13.5%	Functional Class of Accum. Depr'n	(799.6)	(336.2)	(79.9)	(121.5)				
Allowance For Working Capital	129.8	17.2	13.2%	12.50% of OM&A and Taxes	10.5	3.8	1.3	1.6				
Inventories (Schedule 2.13)	450.2	99.4	22.1%	Functional Class of Inventories	60.4	22.2	7.9	8.9				
Other Assets (Schedule 2.13)	88.2	6.3	7.1%	Functional Classification of Other Assets	3.8	1.4	0.5	0.6				
Total Rate Base	12,888.0	2,731.2	21.2%		1,701.5	597.8	128.5	303.3				
Revenue Requirement												
Fuel Expense SaskPower Units	589.4	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-				
Purchased Power & Import	258.5	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-				
Export & Net Electricity Trading Revenue (Credit)	(51.9)	-	0.0%	Functional Class of Exports	-	-	-	-				
Operating, Maintenance & Administration (Schedule 2.14)	932.9	122.4	13.1%	Functional Class of OM&A	74.4	27.3	9.8	10.9				
Depreciation & Depletion (Schedule 2.15)	723.1	106.0	14.7%	Functional Class of Depr'n & Depletion	63.9	26.1	4.8	11.2				
Corporate Capital Tax	70.0	14.9	21.3%	Functional Class of Corp. Capital Tax	9.3	3.3	0.7	1.7				
Grants in Lieu of Taxes	34.4	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-				
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	(4.9)	(18.2)	(0.3)	-				
Other Income (Credit) (Schedule 2.16)	(132.1)	(24.2)	18.3%	Functional Class of Other Income	78.0	27.4	5.9	13.9				
Return on Rate Base @ 4.59%	591.1	125.3	21.2%	Rate Base								
Total Revenue Requirement	3,016.4	344.3	11.4%		220.8	65.8	20.9	36.8				

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details TRANSMISSION PLANT IN SERVICE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Generation Assets											
Power Production	9,631.8	-	0.0%	-		-		-		-	
Power Production - PPA	1,218.4	-	0.0%	-		-		-		-	
Coal Reserves	75.0	-	0.0%	-		-		-		-	
Shand Greenhouse	6.0	-	0.0%	-		-		-		-	
Total Generation Assets	10,931.2	-	0.0%	-		-		-		-	
Transmission Assets											
Transmission Assets	3,592.9	3,549.4	98.8%	2,185.5		818.3		167.0		378.6	
Total Transmission Assets	3,592.9	3,549.4	98.8%	2,185.5		818.3		167.0		378.6	
Distribution Assets											
Distribution Assets	5,809.9	-	0.0%	-		-		-		-	
Meters	132.5	-	0.0%	-		-		-		-	
Instrument Transformers	22.7	-	0.0%	-		-		-		-	
Total Distribution Assets	5,965.1	-	0.0%	-		-		-		-	
General Plant Assets											
Unused Land	2.3	0.3	13.1%	0.2		0.1		0.0		0.0	
Right of Use Land	10.3	1.3	13.1%	0.8		0.3		0.1		0.1	
Buildings	720.0	141.7	19.7%	86.2		31.6		11.3		12.6	
Right of Use Buildings	7.9	1.6	20.5%	1.0		0.4		0.1		0.1	
Office Furniture & Equipment	62.9	12.4	19.7%	7.5		2.8		1.0		1.1	
Vehicles & Equipment	259.9	86.3	33.2%	52.5		19.3		6.9		7.7	
Computer Development & Equipment	404.9	62.2	15.3%	37.8		13.9		5.0		5.5	
Communication, Protection & Control	144.8	81.1	56.0%	49.3		18.1		6.5		7.2	
Tools & Equipment	27.0	9.2	34.0%	5.6		2.1		0.7		0.8	
Total General Plant Assets	1,640.0	396.1	24.2%	240.9		88.4		31.6		35.3	
Total Plant In Service	22,129.2	3,945.6	17.8%	2,426.4		906.7		198.7		413.9	

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details							
TRANSMISSION ACCUMULATED DEPRECIATION							
2026 Fiscal Test Embedded Cost of Service Study							
(\$ Millions)							
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials	
				Demand		Demand	
Generation Assets							
Power Production	(4,906.6)	-	0.0%	-	-	-	-
Power Production - PPA	(718.4)	-	0.0%	-	-	-	-
Coal Reserves	(53.0)	-	0.0%	-	-	-	-
Shand Greenhouse	(4.5)	-	0.0%	-	-	-	-
Total Generation Assets	(5,682.4)	-	0.0%	-	-	-	-
Transmission Assets							
Transmission Assets	(1,169.5)	(1,147.9)	98.2%	(684.4)	(294.0)	(64.8)	(104.7)
Total Transmission Assets	(1,169.5)	(1,147.9)	98.2%	(684.4)	(294.0)	(64.8)	(104.7)
Distribution Assets							
Distribution Assets	(2,256.7)	-	0.0%	-	-	-	-
Meters	(71.1)	-	0.0%	-	-	-	-
Instrument Transformers	(16.4)	-	0.0%	-	-	-	-
Total Distribution Assets	(2,344.2)	-	0.0%	-	-	-	-
General Plant Assets							
Unused Land	-	-	0.0%	-	-	-	-
Right of Use Land	(4.5)	(0.6)	13.1%	(0.4)	(0.1)	(0.0)	(0.1)
Buildings	(92.7)	(17.1)	18.4%	(10.4)	(3.8)	(1.4)	(1.5)
Right of Use Buildings	(6.0)	(1.2)	20.5%	(0.7)	(0.3)	(0.1)	(0.1)
Office Furniture & Equipment	(34.7)	(6.4)	18.4%	(3.9)	(1.4)	(0.5)	(0.6)
Vehicles & Equipment	(151.6)	(51.0)	33.7%	(31.0)	(11.4)	(4.1)	(4.5)
Computer Development & Equipment	(299.0)	(47.6)	15.9%	(29.0)	(10.6)	(3.8)	(4.2)
Communication, Protection & Control	(106.5)	(58.6)	55.0%	(35.6)	(13.1)	(4.7)	(5.2)
Tools & Equipment	(18.2)	(6.9)	37.7%	(4.2)	(1.5)	(0.5)	(0.6)
Total General Plant Assets	(713.3)	(189.4)	26.6%	(115.2)	(42.2)	(15.1)	(16.9)
Total Accumulated Depreciation	(9,909.4)	(1,337.3)	13.5%	(799.6)	(336.2)	(79.9)	(121.5)

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details									
TRANSMISSION INVENTORIES									
2026 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Inventories											
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-	-	-
Power Production - Fuel	53.1	-	0.0%	-	-	-	-	-	-	-	-
Transmission & Distribution	252.9	99.6	39.4%	60.6	22.2	22.2	7.9	7.9	8.9	8.9	8.9
Miscellaneous (Computers, Power Shop)	(1.4)	(0.2)	13.1%	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Inventories	450.2	99.4	22.1%	60.4	22.2	22.2	7.9	7.9	8.9	8.9	8.9

Functionalization and Classification of Financial Account Details									
TRANSMISSION OTHER ASSETS									
2026 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Other Assets											
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.2	4.0%	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	6.1	13.1%	3.7	1.4	1.4	0.5	0.5	0.5	0.5	0.5
Total Other Assets	88.2	6.3	7.1%	3.8	1.4	1.4	0.5	0.5	0.6	0.6	0.6

Schedule 2.14: Functional Classification of Financial Account Details – Transmission OM&A Expenses

Functionalization and Classification of Financial Account Details TRANSMISSION OM&A EXPENSE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials		
				Demand	Demand	Demand	Demand		
Generation Expenses									
Power Plant Operation	303.1	-	0.0%	-	-	-	-		
Power Production Overhead	40.9	-	0.0%	-	-	-	-		
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-		
Total Generation Expenses	362.5	-	0.0%	-	-	-	-		
Transmission & Distribution Expenses									
Planning Support	24.0	10.6	44.2%	6.5	2.4	0.5	1.1		
Transmission Including 230/138 & 72 kV Radials	66.7	66.7	100.0%	40.5	14.8	5.7	5.8		
Distribution	118.9	-	0.0%	-	-	-	-		
Customer Services	8.7	-	0.0%	-	-	-	-		
Metering Services	5.5	-	0.0%	-	-	-	-		
Total Transmission & Distribution Expenses	223.8	77.3	34.5%	47.0	17.2	6.2	6.9		
Customer Services Expenses									
Meter Reading	14.7	-	0.0%	-	-	-	-		
Billing Services	4.0	-	0.0%	-	-	-	-		
Collections/Special Collections	2.0	-	0.0%	-	-	-	-		
Bad Debt Expense	10.3	-	0.0%	-	-	-	-		
Marketing & Sales	3.2	-	0.0%	-	-	-	-		
Demand Side Management	-	-	0.0%	-	-	-	-		
Customer Service	26.5	-	0.0%	-	-	-	-		
Total Customer Services Expenses	60.7	-	0.0%	-	-	-	-		
Support Group Expenses									
President / Board	2.5	0.3	13.1%	0.2	0.1	0.0	0.0		
Corporate & Financial Services (C&FS)	12.0	2.2	18.4%	1.3	0.5	0.2	0.2		
C&FS - Insurance Premiums & Insurable Losses	20.4	0.8	4.0%	0.5	0.2	0.1	0.1		
Asset Management, Planning, & Sustainability	28.5	5.2	18.1%	3.1	1.1	0.4	0.5		
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-		
SMR Consortium	7.4	-	0.0%	-	-	-	-		
General Council / Land	5.5	0.7	13.1%	0.4	0.2	0.1	0.1		
Safety	7.6	1.3	16.9%	0.8	0.3	0.1	0.1		
Corporate Information & Technology	111.8	19.4	17.4%	11.8	4.3	1.5	1.7		
Human Resources	36.2	7.6	20.9%	4.6	1.7	0.6	0.7		
Commercial & Industrial Operations	12.8	-	0.0%	-	-	-	-		
Procurement & Supply Chain	41.4	7.6	18.4%	4.6	1.7	0.6	0.7		
Total Support Group Expenses	286.0	45.1	15.8%	27.4	10.1	3.6	4.0		
Total OM&A Expenses	932.9	122.4	13.1%	74.4	27.3	9.8	10.9		

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details TRANSMISSION DEPRECIATION & DEPLETION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
				Demand	Demand	Demand	Demand
Generation Assets							
Power Production	320.5	-	0.0%	-	-	-	-
Purchase Power Agreements (PPA)	54.5	-	0.0%	-	-	-	-
Coal Reserves	3.0	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation Assets	378.1	-	0.0%	-	-	-	-
Transmission Assets							
Transmission Assets	89.6	88.4	98.7%	53.3	22.1	3.4	9.6
Total Transmission Assets	89.6	88.4	98.7%	53.3	22.1	3.4	9.6
Distribution Assets							
Distribution Assets	169.7	-	0.0%	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-
Instrument Transformers	1.3	-	0.0%	-	-	-	-
Total Distribution Assets	178.7	-	0.0%	-	-	-	-
General Plant Assets							
Unused Land	(0.0)	(0.0)	13.1%	(0.0)	(0.0)	(0.0)	(0.0)
Right of Use Land	0.7	0.1	13.1%	0.1	0.0	0.0	0.0
Buildings	15.3	3.1	20.2%	1.9	0.7	0.2	0.3
Right of Use Buildings	1.9	0.4	20.5%	0.2	0.1	0.0	0.0
Office Furniture & Equipment	3.6	0.7	20.2%	0.4	0.2	0.1	0.1
Vehicles & Equipment	13.1	4.5	34.2%	2.7	1.0	0.4	0.4
Computer Development & Equipment	36.8	6.4	17.3%	3.9	1.4	0.5	0.6
Communication, Protection & Control	2.5	1.5	60.4%	0.9	0.3	0.1	0.1
Tools & Equipment	2.8	0.9	31.8%	0.5	0.2	0.1	0.1
Total General Plant Assets	76.7	17.5	22.9%	10.7	3.9	1.4	1.6
Total Depreciation & Depletion	723.1	106.0	14.7%	63.9	26.1	4.8	11.2

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details							
TRANSMISSION OTHER INCOME							
2026 Fiscal Test Embedded Cost of Service Study							
(\$ Millions)							
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
				Demand	Demand	Demand	Demand
Other Income							
Customer Services Payment Charges	(8.0)	-	0.0%	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-
Transmission	(3.8)	(3.3)	85.8%	(2.0)	(0.7)	(0.3)	(0.3)
Distribution	(7.5)	-	0.0%	-	-	-	-
Miscellaneous Other Income	(2.7)	(0.4)	13.1%	(0.2)	(0.1)	(0.0)	(0.0)
Customer Contribution Revenue	(79.7)	(20.6)	25.8%	(2.6)	(17.4)	-	(0.6)
Green Power Premium	(0.0)	-	0.0%	-	-	-	-
Flyash Sales & Wind Power	(10.7)	-	0.0%	-	-	-	-
CO2 Sales & Penalties	(16.7)	-	0.0%	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-
Total Other Income	(132.1)	(24.2)	18.3%	(4.9)	(18.2)	(0.3)	(0.9)

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details																			
DISTRIBUTION Related Costs																			
2025 Fiscal Test Embedded Cost of Service Study (\$Millions)																			
Rate Base and Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Basis of Classification	Area Substitutions		Distribution Net/ins		Urban Laterals		Rural Laterals		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streightlights
					Demand		Demand		Demand		Demand		Demand						
Rate Base																			
Plant In Service (Schedule 2.21)	22,129.2 (9909.4)	6,430.9 (2,544.9)	29.3% (25.7%)	Functional Class of PHS	584.6 (226.2)	1,773.4 (729.7)	193.8 (89.3)	452.2 (208.4)	360.0 (166.0)	840.1 (387.4)	501.4 (167.2)	270.0 (90.0)	1,130.4 (331.0)	22.7 (16.4)	132.5 (71.1)	-	-	-	-
Accumulated Depreciation (Schedule 2.22)				Functional Class of Accum. Dep'n															
Allowance For Working Capital	12,938	25.2	19.4%	12.50% of OM&A and Taxes	2.3	7.1	1.0	2.4	1.9	4.5	2.4	1.3	1.0	0.0	0.0	-	-	-	-
Inventories (Schedule 2.23)	450.2	133.0	34.0%	Functional Class of Inventories	13.9	43.6	6.6	15.3	12.3	28.8	14.9	8.0	2.6	-	-	-	-	-	-
Other Assets (Schedule 2.23)	88.2	9.2	10.4%	Functional Classification of Other Assets	0.8	2.6	0.4	0.9	0.7	1.7	0.9	0.5	-	-	-	-	-	-	-
Total Rate Base	12,883.0	4,073.3	31.6%		375.4	1,097.1	112.5	262.4	209.0	487.7	352.5	188.8	803.1	6.3	61.4	-	-	-	-
Revenue Requirement																			
Fuel Expense SaskPower Units	589.4	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power & Import	258.5	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(51.9)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.24)	93.29	179.4	19.2%	Functional Class of OM&A	16.3	51.2	7.7	18.0	14.5	33.8	17.5	9.4	3.0	-	-	-	-	-	-
Depreciation & Depletion (Schedule 2.25)	723.1	200.9	27.8%	Functional Class of Dep'n & Depletion	18.7	48.8	6.2	14.4	11.5	26.8	17.4	9.4	31.8	1.3	7.7	-	-	-	-
Corporate Capital Tax	700	22.3	31.8%	Functional Class of Corp. Capital Tax	2.1	6.0	0.6	1.4	1.1	2.6	1.9	1.0	4.6	0.0	0.4	-	-	-	-
Grants in Lieu of Taxes	34.4	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Income (Credit) (Schedule 2.26)	(132.1)	(67.1)	50.8%	Functional Class of Other Income	(0.7)	(4.1)	(1.1)	(2.5)	(2.8)	(6.5)	(0.8)	(0.4)	(43.9)	-	-	-	-	-	-
Return on Rate Base @ 4.59%	39.11	186.8	31.6%	Rate Base	31.2	50.3	17.2	12.0	9.6	22.4	16.2	8.7	36.8	0.3	2.8	-	-	-	-
Total Revenue Requirement	3,016.4	5,223	17.3%		53.6	152.2	18.6	43.3	33.9	79.0	52.2	28.1	32.3	1.7	10.8	-	-	-	-

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details																			
DISTRIBUTION PLANT IN SERVICE																			
2026 Fiscal Test Embedded Cost of Service Study																			
(\$ Millions)																			
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Transformers	Services	Instrument Transformers	Amortization Contributions	Meters	Streetlights
				Demand		Demand		Demand	Customer	Demand	Customer	Demand	Customer						
Generation Assets																			
Power Production - PPA	9,631.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Coal	1,218.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	75.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shard Greenhouse	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	10,931.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Assets																			
Transmission Assets	3,592.9	36.1	1.0%	36.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	3,592.9	36.1	1.0%	36.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Assets																			
Distribution Assets	5,809.9	5,809.9	100.0%	509.5	1,650.8	175.3	409.1	325.4	759.2	459.6	247.5	1,123.1	-	1,123.1	-	-	-	-	150.4
Meters	132.5	132.5	100.0%	-	-	-	-	-	-	-	-	-	-	-	-	22.7	-	-	132.5
Instrument Transformers	22.7	22.7	100.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	5,965.1	5,965.1	100.0%	509.5	1,650.8	175.3	409.1	325.4	759.2	459.6	247.5	1,123.1	-	1,123.1	22.7	-	-	132.5	150.4
General Plant Assets																			
Unused Land	2.3	0.4	19.2%	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	-	0.0	-	-	-	-	0.0
Right of Use Land	10.3	2.0	19.2%	0.2	0.6	0.1	0.2	0.2	0.4	0.2	0.1	0.0	-	0.0	-	-	-	-	0.1
Buildings	720.0	189.1	26.3%	17.2	53.9	8.1	19.0	15.2	35.6	18.4	9.9	3.2	-	3.2	-	-	-	-	8.5
Right of Use Buildings	7.9	2.1	27.3%	0.2	0.6	0.1	0.2	0.2	0.4	0.2	0.1	0.0	-	0.0	-	-	-	-	0.1
Office Furniture & Equipment	62.9	16.5	26.3%	1.5	4.7	0.7	1.7	1.3	3.1	1.6	0.9	0.3	-	0.3	-	-	-	-	0.7
Vehicles & Equipment	259.9	113.8	43.8%	10.3	32.5	4.9	11.4	9.2	21.4	11.1	6.0	1.9	-	1.9	-	-	-	-	5.1
Computer Development & Equipment	404.9	80.2	19.8%	7.3	22.9	3.4	8.0	6.5	15.1	7.8	4.2	1.4	-	1.4	-	-	-	-	3.6
Communication Protection & Control	144.8	16.5	11.4%	1.5	4.7	0.7	1.7	1.3	3.1	1.6	0.9	0.3	-	0.3	-	-	-	-	0.7
Tools & Equipment	27.0	9.0	33.2%	0.8	2.6	0.4	0.9	0.7	1.7	0.9	0.5	0.2	-	0.2	-	-	-	-	0.4
Total General Plant Assets	1,640.0	429.7	26.2%	39.0	122.5	18.5	43.1	34.6	80.8	41.9	22.5	7.3	-	7.3	-	-	-	-	19.4
Total Plant in Service	22,120.2	6,430.9	29.1%	584.6	1,773.4	193.8	452.2	360.0	840.1	501.4	270.0	1,130.4	-	1,130.4	22.7	-	-	132.5	169.8

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details DISTRIBUTION ACCUMULATED DEPRECIATION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Streetlights
				Demand	Customer	Demand	Customer	Demand	Customer	Demand	Customer	Demand	Customer	
Generation Assets														
Power Production	(4,906.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Power Production - PPA	(718.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	(53.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Stand Greenhouse	(6.5)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	(5,684.4)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission Assets														
Transmission Assets	(1,169.5)	(19.8)	1.7%	(19.8)	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	(1,169.5)	(19.8)	1.7%	(19.8)	-	-	-	-	-	-	-	-	-	-
Distribution Assets														
Distribution Assets	(2,256.7)	(2,256.7)	100.0%	(190.0)	(81.5)	(678.1)	(151.4)	(190.3)	(353.4)	(149.5)	(80.5)	(328.0)	(16.4)	(54.0)
Meters	(71.1)	(71.1)	100.0%	-	-	-	-	-	-	-	-	-	-	(71.1)
Instrument Transformers	(16.4)	(16.4)	100.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	(2,344.2)	(2,344.2)	100.0%	(190.0)	(81.5)	(678.1)	(151.4)	(190.3)	(353.4)	(149.5)	(80.5)	(328.0)	(16.4)	(54.0)
General Plant Assets														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Right of Use Land	(4.5)	(0.9)	19.2%	(0.1)	(0.1)	(0.2)	(0.1)	-	(0.1)	(0.1)	(0.0)	(0.0)	-	(0.0)
Buildings	(92.7)	(22.8)	24.6%	(2.1)	(6.5)	(1.8)	(4.3)	(2.3)	(1.8)	(2.2)	(1.2)	(0.4)	-	(1.0)
Right of Use Buildings	(6.0)	(1.6)	27.3%	(0.1)	(0.5)	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.1)	(0.0)	-	(0.1)
Office Furniture & Equipment	(34.7)	(8.5)	24.6%	(0.8)	(2.4)	(0.4)	(0.9)	(0.9)	(0.7)	(0.8)	(0.4)	(0.1)	-	(0.4)
Vehicles & Equipment	(151.6)	(67.3)	44.4%	(6.1)	(19.2)	(2.9)	(6.7)	(6.2)	(5.4)	(12.7)	(3.5)	(6.6)	-	(3.0)
Computer Development & Equipment	(299.0)	(61.7)	20.6%	(5.6)	(17.6)	(2.7)	(5.0)	(11.6)	(6.0)	(6.0)	(3.2)	(1.1)	-	(2.8)
Communication, Protection & Control	(108.5)	(12.6)	11.8%	(1.1)	(3.6)	(0.5)	(1.3)	(0.6)	(1.2)	(0.7)	(0.3)	(0.1)	-	(0.6)
Tools & Equipment	(18.2)	(5.6)	30.5%	(0.5)	(1.6)	(0.2)	(0.4)	(0.6)	(1.0)	(0.5)	(0.3)	(0.1)	-	(0.3)
Total General Plant Assets	(713.3)	(181.0)	25.4%	(16.4)	(51.6)	(7.8)	(14.6)	(18.1)	(34.1)	(17.6)	(9.5)	(3.1)	-	(8.2)
Total Accumulated Depreciation	(9,909.4)	(2,544.9)	25.7%	(228.2)	(729.7)	(89.3)	(166.0)	(208.4)	(387.4)	(167.2)	(90.0)	(331.0)	(16.4)	(62.1)

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details															
DISTRIBUTION INVENTORIES															
2026 Fiscal Test Embedded Cost of Service Study															
(\$ Millions)															
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	
				Demand		Demand		Demand		Demand		Demand		Customer	
Inventories															
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Power Production - Fuel	53.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Transmission & Distribution	252.9	153.3	60.6%	13.9	43.7	43.7	15.4	12.4	28.8	14.9	8.0	2.6	2.6	8.0	6.9
Miscellaneous (Computers, Power Shop)	(1.4)	(0.3)	19.2%	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Inventories	450.2	153.0	34.0%	13.9	43.6	43.6	15.3	12.3	28.8	14.9	8.0	2.6	2.6	8.0	6.9
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	
				Demand		Demand		Demand		Demand		Demand		Customer	
Other Assets															
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.3	5.3%	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	8.9	19.2%	0.8	2.5	2.5	0.3	0.7	1.7	0.9	0.3	0.2	0.2	0.3	0.2
Total Other Assets	88.2	9.2	10.4%	0.8	2.6	2.6	0.3	0.7	1.7	0.9	0.3	0.2	0.2	0.3	0.2

Schedule 2.24: Functional Classification of Financial Account Details – Distribution OM&A Expenses

Functionalization and Classification of Financial Account Details																	
DISTRIBUTION OM&A EXPENSES																	
2026 Fiscal Test Embedded Cost of Service Study																	
(\$ Millions)																	
Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations	Distribution Mains		Urban Laterals	Rural Laterals	Transformers Demand	Transformers Customer	Services Customer	Instrument Transformers Customer	Amortization Customer Contributions Customer	Meters Customer	Streetlights Customer		
					Demand	Total											
Generation Expenses																	
Power Plant Operation	303.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Production Overhead	40.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Generation Expenses	362.5		0.0%														
Transmission & Distribution Expenses																	
Planning Support	24.0	0.1	0.4%	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	
Transmission Including 230/138 & 72 kV Radials	66.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution	118.9	118.9	100.0%	10.8	33.9	-	5.1	11.9	9.6	22.4	11.6	6.2	2.0	-	-	5.4	
Customer Services	8.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Metering Services	5.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Transmission & Distribution Expenses	223.8	119.0	53.2%	10.8	33.9		5.1	11.9	9.6	22.4	11.6	6.2	2.0	-	-	5.4	
Customer Services Expenses																	
Meter Reading	14.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Billing Services	4.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Collections/Special Collections	2.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Bad Debt Expense	10.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Marketing & Sales	3.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Demand Side Management	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Customer Service	26.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Customer Services Expenses	60.7		0.0%														
Support Group Expenses																	
President / Board	2.5	0.5	19.2%	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	-	-	-	0.0	
Corporate & Financial Services (C&FS)	12.0	2.9	24.6%	0.3	0.8	0.3	0.1	0.3	0.2	0.6	0.3	0.2	0.0	-	-	0.1	
C&FS - Insurance Premiums & Insurable Losses	20.4	1.1	5.3%	0.1	0.3	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.0	-	-	0.0	
Asset Management, Planning, & Sustainability	28.5	6.9	24.2%	0.6	2.0	0.6	0.3	0.7	0.6	1.3	0.7	0.4	0.1	-	-	0.3	
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
SMR Consortium	7.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
General Council / Land	5.5	1.1	19.2%	0.1	0.3	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.0	-	-	0.0	
Safety	7.6	1.8	23.3%	0.2	0.5	0.1	0.1	0.2	0.1	0.3	0.2	0.1	0.0	-	-	0.1	
Corporate Information & Technology	111.8	25.7	23.0%	2.3	7.3	2.3	1.1	2.6	2.1	4.8	2.5	1.4	0.4	-	-	1.2	
Human Resources	36.2	10.3	28.4%	0.9	2.9	0.9	0.4	1.0	0.8	1.9	1.0	0.5	0.2	-	-	0.5	
Commercial & Industrial Operations	12.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	
Procurement & Supply Chain	41.4	10.2	24.6%	0.9	2.9	0.9	0.4	1.0	0.8	1.9	1.0	0.5	0.2	-	-	0.5	
Total Support Group Expenses	286.0	60.4	21.1%	5.5	17.2		2.6	6.1	4.9	11.4	5.9	3.2	1.0	-	-	2.7	
Total OM&A Expenses	982.9	179.4	18.2%	16.3	51.2		7.7	18.0	14.5	33.8	17.5	9.4	3.0	-	-	8.1	

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details DISTRIBUTION DEPRECIATION & DEPLETION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Streetlights
				Demand	0.0%	Demand	0.0%	Demand	0.0%	Demand	0.0%	Demand	0.0%	
Generation Assets														
Power Production	320.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	54.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	3.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Stand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	378.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission Assets														
Transmission Assets	89.6	1.0	1.1%	-	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	89.6	1.0	1.1%	-	-	-	-	-	-	-	-	-	-	-
Distribution Assets														
Distribution Assets	169.7	169.7	100.0%	15.8	42.7	5.3	12.3	9.8	22.8	15.4	8.3	31.5	-	5.9
Meters	7.7	7.7	100.0%	-	-	-	-	-	-	-	-	-	-	7.7
Instrument Transformers	1.3	1.3	100.0%	-	-	-	-	-	-	-	-	-	1.3	-
Total Distribution Assets	178.7	178.7	100.0%	15.8	42.7	5.3	12.3	9.8	22.8	15.4	8.3	31.5	1.3	5.9
General Plant Assets														
Unused Land	(0.0)	(0.0)	19.2%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	(0.0)
Right of Use Land	0.7	0.1	19.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Buildings	15.3	4.1	27.0%	0.4	1.2	0.2	0.4	0.3	0.8	0.4	0.2	0.1	-	0.2
Right of Use Buildings	1.9	0.5	27.3%	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.0	0.0	-	0.0
Office Furniture & Equipment	3.6	1.0	27.0%	0.1	0.3	0.0	0.1	0.1	0.1	0.1	0.1	0.0	-	0.0
Vehicles & Equipment	13.1	5.9	45.1%	0.5	1.7	0.3	0.6	0.5	1.1	0.6	0.3	0.1	-	0.3
Computer Development & Equipment	36.8	8.4	22.9%	0.8	2.4	0.4	0.8	0.7	1.6	0.8	0.4	0.1	-	0.4
Communication, Protection & Control	2.5	0.2	10.0%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Tools & Equipment	2.8	0.8	28.7%	0.1	0.2	0.0	0.1	0.1	0.2	0.1	0.1	0.0	-	0.0
Total General Plant Assets	76.7	21.1	27.6%	1.9	6.0	0.9	2.1	1.7	4.0	2.1	1.1	0.4	-	1.0
Total Depreciation & Depletion	723.1	200.9	27.8%	18.7	48.8	6.2	14.4	11.5	26.8	17.4	9.4	31.8	1.3	6.9

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details													
DISTRIBUTION OTHER INCOME													
2026 Fiscal Test Embedded Cost of Service Study													
(\$ Millions)													
Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals	
				Demand		Demand		Demand		Demand		Demand	
Other Income													
Customer Services Payment Charges	(8.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Transmission	(3.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Distribution	(7.5)	(7.5)	100.0%	(0.7)	(0.3)	(2.1)	(0.7)	(0.7)	(0.7)	(0.4)	(0.1)	(1.4)	(0.3)
Miscellaneous Other Income	(2.7)	(0.5)	19.2%	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)
Customer Contribution Revenue	(79.7)	(59.1)	74.2%	(0.0)	(0.7)	(1.8)	(0.7)	(1.7)	(2.2)	(5.0)	(43.8)	(3.9)	(3.9)
Green Power Premium	(0.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(10.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-
CO2 Sales & Penalties	(16.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Other Income	(132.1)	(67.1)	50.8%	(0.7)	(1.1)	(4.1)	(1.1)	(2.5)	(2.8)	(6.5)	(0.8)	(43.9)	(4.2)

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details CUSTOMER SERVICE Related Costs 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Rate Base										
Plant in Service (Schedule 2.31)	22,129.2	278.2	1.3%	Functional Class of PIS	19.9	58.4	14.7	67.8	104.2	13.2
Accumulated Depreciation (Schedule 2.32)	(9,909.4)	(86.6)	0.9%	Functional Class of Accum. Depr'n	(8.4)	(17.1)	(4.2)	(22.3)	(30.5)	(4.0)
Allowance For Working Capital	129.8	13.4	10.3%	12.50% of OM&A and Taxes	1.0	2.8	0.7	3.3	4.9	0.6
Inventories (Schedule 2.33)	450.2	(0.2)	0.0%	Functional Class of Inventories	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)
Other Assets (Schedule 2.33)	88.2	5.3	6.0%	Functional Classification of Other Assets	0.4	1.1	0.3	1.3	1.9	0.2
Total Rate Base	12,888.0	210.2	1.6%		13.0	45.1	11.5	50.0	80.6	10.0
Revenue Requirement										
Fuel Expense SaskPower Units	589.4	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	258.5	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(51.9)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.34)	932.9	106.0	11.4%	Functional Class of OM&A	8.3	21.9	5.5	26.3	39.1	4.8
Depreciation & Depletion (Schedule 2.35)	723.1	11.8	1.6%	Functional Class of Depr'n & Depletion	1.0	2.4	0.6	3.0	4.3	0.5
Corporate Capital Tax	70.0	1.1	1.6%	Functional Class of Corp. Capital Tax	0.1	0.2	0.1	0.3	0.4	0.1
Grants in Lieu of Taxes	34.4	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	-	-	-	-	-	-
Other Income (Credit) (Schedule 2.36)	(132.1)	(10.5)	7.9%	Functional Class of Other Income	(0.0)	(2.2)	(5.3)	(2.8)	(0.1)	(0.0)
Return on Rate Base @ 4.59%	591.1	9.6	1.6%	Rate Base	0.6	2.1	0.5	2.3	3.7	0.5
Total Revenue Requirement	3,016.4	118.0	3.9%		9.9	24.4	1.3	29.0	47.4	5.9

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES PLANT IN SERVICE 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer	
Generation Assets										
Power Production	9,631.8	-	0.0%	-	-	-	-	-	-	-
Power Production - PPA	1,218.4	-	0.0%	-	-	-	-	-	-	-
Coal Reserves	75.0	-	0.0%	-	-	-	-	-	-	-
Shand Greenhouse	6.0	-	0.0%	-	-	-	-	-	-	-
Total Generation Assets	10,931.2	-	0.0%	-	-	-	-	-	-	-
Transmission Assets										
Transmission Assets	3,592.9	-	0.0%	-	-	-	-	-	-	-
Total Transmission Assets	3,592.9	-	0.0%	-	-	-	-	-	-	-
Distribution Assets										
Distribution Assets	5,809.9	-	0.0%	-	-	-	-	-	-	-
Meters	132.5	-	0.0%	-	-	-	-	-	-	-
Instrument Transformers	22.7	-	0.0%	-	-	-	-	-	-	-
Total Distribution Assets	5,965.1	-	0.0%	-	-	-	-	-	-	-
General Plant Assets										
Unused Land	2.3	0.3	11.4%	0.0	0.1	0.0	0.1	0.1	0.0	0.0
Right of Use Land	10.3	1.2	11.4%	0.1	0.2	0.1	0.3	0.4	0.1	0.1
Buildings	720.0	180.0	25.0%	8.8	39.7	10.2	41.5	71.1	8.7	8.7
Right of Use Buildings	7.9	2.0	25.7%	0.1	0.4	0.1	0.5	0.8	0.1	0.1
Office Furniture & Equipment	62.9	15.7	25.0%	0.8	3.5	0.9	3.6	6.2	0.8	0.8
Vehicles & Equipment	259.9	21.6	8.3%	5.3	2.8	0.5	7.4	4.9	0.7	0.7
Computer Development & Equipment	404.9	54.1	13.4%	3.7	11.4	2.9	13.1	20.4	2.5	2.5
Communication, Protection & Control	144.8	2.2	1.6%	0.8	0.1	-	0.9	0.2	0.3	0.3
Tools & Equipment	27.0	1.1	4.1%	0.4	0.1	-	0.5	0.1	0.0	0.0
Total General Plant Assets	1,640.0	278.2	17.0%	19.9	58.4	14.7	67.8	104.2	13.2	13.2
Total Plant In Service	22,129.2	278.2	1.3%	19.9	58.4	14.7	67.8	104.2	13.2	13.2

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES ACCUMULATED DEPRECIATION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer	
Generation Assets										
Power Production	(4,906.6)	-	0.0%	-	-	-	-	-	-	-
Power Production - PPA	(718.4)	-	0.0%	-	-	-	-	-	-	-
Coal Reserves	(53.0)	-	0.0%	-	-	-	-	-	-	-
Shand Greenhouse	(4.5)	-	0.0%	-	-	-	-	-	-	-
Total Generation Assets	(5,682.4)	-	0.0%	-	-	-	-	-	-	-
Transmission Assets										
Transmission Assets	(1,169.5)	-	0.0%	-	-	-	-	-	-	-
Total Transmission Assets	(1,169.5)	-	0.0%	-	-	-	-	-	-	-
Distribution Assets										
Distribution Assets	(2,256.7)	-	0.0%	-	-	-	-	-	-	-
Meters	(71.1)	-	0.0%	-	-	-	-	-	-	-
Instrument Transformers	(16.4)	-	0.0%	-	-	-	-	-	-	-
Total Distribution Assets	(2,344.2)	-	0.0%	-	-	-	-	-	-	-
General Plant Assets										
Unused Land	-	-	0.0%	-	-	-	-	-	-	-
Right of Use Land	(4.5)	(0.5)	11.4%	(0.0)	(0.1)	(0.0)	(0.1)	(0.2)	(0.0)	(0.0)
Buildings	(92.7)	(21.4)	23.1%	(1.1)	(4.7)	(1.2)	(4.9)	(8.4)	(1.0)	(1.0)
Right of Use Buildings	(6.0)	(1.5)	25.7%	(0.1)	(0.3)	(0.1)	(0.4)	(0.6)	(0.1)	(0.1)
Office Furniture & Equipment	(34.7)	(8.0)	23.1%	(0.4)	(1.8)	(0.5)	(1.8)	(3.2)	(0.4)	(0.4)
Vehicles & Equipment	(151.6)	(12.8)	8.5%	(3.1)	(1.7)	(0.3)	(4.4)	(2.9)	(0.4)	(0.4)
Computer Development & Equipment	(293.0)	(39.9)	13.3%	(2.9)	(8.4)	(2.1)	(9.7)	(14.9)	(1.9)	(1.9)
Communication, Protection & Control	(106.5)	(1.7)	1.6%	(0.6)	(0.1)	-	(0.7)	(0.2)	(0.2)	(0.2)
Tools & Equipment	(18.2)	(0.7)	3.8%	(0.3)	(0.0)	-	(0.3)	(0.1)	(0.0)	(0.0)
Total General Plant Assets	(713.3)	(86.6)	12.1%	(8.4)	(17.1)	(4.2)	(22.3)	(30.5)	(4.0)	(4.0)
Total Accumulated Depreciation	(9,909.4)	(86.6)	0.9%	(8.4)	(17.1)	(4.2)	(22.3)	(30.5)	(4.0)	(4.0)

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES INVENTORIES 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Inventories									
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	53.1	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	252.9	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	(1.4)	(0.2)	11.4%	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)
Total Inventories	450.2	(0.2)	0.0%	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES OTHER ASSETS 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.0	0.6%	0.0	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	5.2	11.4%	0.4	1.1	0.3	1.3	1.9	0.2
Total Other Assets	88.2	5.3	6.0%	0.4	1.1	0.3	1.3	1.9	0.2

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services OM&A Expenses

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES OM&A EXPENSES 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer	
Generation Expenses										
Power Plant Operation	303.1	-	0.0%	-	-	-	-	-	-	-
Power Production Overhead	40.9	-	0.0%	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-	-	-	-
Total Generation Expenses	362.5	-	0.0%	-	-	-	-	-	-	-
Transmission & Distribution Expenses										
Planning Support	24.0	0.3	1.1%	-	-	-	-	-	-	0.3
Transmission Including 230/138 & 72 kV Radials	66.7	-	0.0%	-	-	-	-	-	-	-
Distribution	118.9	-	0.0%	-	-	-	-	-	-	-
Customer Services	8.7	8.7	100.0%	-	1.0	-	6.1	1.5	-	-
Metering Services	5.5	5.5	100.0%	5.5	-	-	-	-	-	-
Total Transmission & Distribution Expenses	223.8	14.5	6.5%	5.5	1.0	-	6.1	1.5	0.3	0.3
Customer Services Expenses										
Meter Reading	14.7	14.7	100.0%	-	14.7	-	-	-	-	-
Billing Services	4.0	4.0	100.0%	-	-	4.0	-	-	-	-
Collections/Special Collections	2.0	2.0	100.0%	-	-	-	2.0	-	-	-
Bad Debt Expense	10.3	10.3	100.0%	-	-	-	10.3	-	-	-
Marketing & Sales	3.2	3.2	100.0%	-	-	-	-	-	-	3.2
Demand Side Management	-	-	0.0%	-	-	-	-	-	-	-
Customer Service	26.5	26.5	100.0%	-	-	-	-	26.5	-	-
Total Customer Services Expenses	60.7	60.7	100.0%	-	14.7	4.0	12.3	26.5	3.2	3.2
Support Group Expenses										
President / Board	2.5	0.3	11.4%	0.0	0.1	0.0	0.1	0.1	0.0	0.0
Corporate & Financial Services (C&FS)	12.0	1.7	13.8%	0.1	0.3	0.1	0.4	0.6	0.1	0.1
C&FS - Insurance Premiums & Insurable Losses	20.4	0.1	0.6%	0.1	0.0	-	0.1	0.0	0.0	0.0
Asset Management, Planning, & Sustainability	28.5	1.8	6.5%	0.3	0.3	0.1	0.6	0.5	0.1	0.1
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-	-
SMR Consortium	7.4	-	0.0%	-	-	-	-	-	-	-
General Council / Land	5.5	0.6	11.4%	0.0	0.1	0.0	0.2	0.2	0.0	0.0
Safety	7.6	0.8	10.4%	0.1	0.2	0.0	0.2	0.3	0.0	0.0
Corporate Information & Technology	111.8	15.6	13.9%	1.2	3.2	0.8	3.8	5.8	0.7	0.7
Human Resources	36.2	4.2	11.6%	0.5	0.8	0.2	1.1	1.4	0.2	0.2
Commercial & Industrial Operations	12.8	-	0.0%	-	-	-	-	-	-	-
Procurement & Supply Chain	41.4	5.7	13.8%	0.5	1.2	0.3	1.4	2.1	0.3	0.3
Total Support Group Expenses	286.0	30.8	10.8%	2.8	6.2	1.5	7.9	11.0	1.4	1.4
Total OM&A Expenses	932.9	106.0	11.4%	8.3	21.9	5.5	26.3	39.1	4.8	4.8

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES DEPRECIATION & DEPLETION 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)											
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services		Meter Reading	Billing & Customer Accounts		Customer Collections	Service & Support	Customer Strategy & Planning
				Customer	Customer		Customer	Customer			
Generation Assets											
Power Production	320.5	-	0.0%	-	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	54.5	-	0.0%	-	-	-	-	-	-	-	-
Coal Reserves	3.0	-	0.0%	-	-	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-
Total Generation Assets	378.1	-	0.0%	-	-	-	-	-	-	-	-
Transmission Assets											
Transmission Assets	89.6	-	0.0%	-	-	-	-	-	-	-	-
Total Transmission Assets	89.6	-	0.0%	-	-	-	-	-	-	-	-
Distribution Assets											
Distribution Assets	169.7	-	0.0%	-	-	-	-	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-	-	-	-	-
Instrument Transformers	1.3	-	0.0%	-	-	-	-	-	-	-	-
Total Distribution Assets	178.7	-	0.0%	-	-	-	-	-	-	-	-
General Plant Assets											
Unused Land	(0.0)	(0.0)	11.4%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Right of Use Land	0.7	0.1	11.4%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Buildings	15.3	3.9	25.5%	0.2	0.9	0.9	0.2	0.9	0.9	1.5	0.2
Right of Use Buildings	1.9	0.5	25.7%	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.0
Office Furniture & Equipment	3.6	0.9	25.5%	0.0	0.2	0.2	0.1	0.2	0.2	0.4	0.0
Vehicles & Equipment	13.1	1.2	9.2%	0.3	0.3	0.2	0.0	0.4	0.3	0.3	0.0
Computer Development & Equipment	36.8	5.1	13.9%	0.4	1.1	1.1	0.3	1.3	1.3	1.9	0.2
Communication, Protection & Control	2.5	0.0	1.4%	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0
Tools & Equipment	2.8	0.1	3.5%	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0
Total General Plant Assets	76.7	11.8	15.4%	1.0	2.4	2.4	0.6	3.0	4.3	0.5	0.5
Total Depreciation & Depletion	723.1	11.8	1.6%	1.0	2.4	2.4	0.6	3.0	4.3	0.5	0.5

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details									
CUSTOMER SERVICES OTHER INCOME									
2026 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
				Customer	Customer	Customer	Customer	Customer	Customer
Other Income									
Customer Services Payment Charges	(8.0)	(8.0)	100.0%	-	-	(5.3)	(2.7)	-	-
Meter Reading	(2.2)	(2.2)	100.0%	-	(2.2)	-	-	-	-
Transmission	(3.8)	-	0.0%	-	-	-	-	-	-
Distribution	(7.5)	-	0.0%	-	-	-	-	-	-
Miscellaneous Other Income	(2.7)	(0.3)	11.4%	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
Customer Contribution Revenue	(79.7)	-	0.0%	-	-	-	-	-	-
Green Power Premium	(0.0)	-	0.0%	-	-	-	-	-	-
Flyash Sales	(10.7)	-	0.0%	-	-	-	-	-	-
CO2 Sales & Penalties	(16.7)	-	0.0%	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-
Total Other Income	(132.1)	(10.5)	7.9%	(0.0)	(2.2)	(5.3)	(2.8)	(0.1)	(0.0)

Schedule 3.0: SaskPower Allocation Methodology Summary



SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology	# of Years of Data For Large Customer (s)
GENERATION	Demand	Load, Losses and Ancillary Services	Coincident Peak Method (ZCP) - at output of Generation and step up transformation.	5
	Energy	Load and Losses	Energy plus Losses.	N/A
TRANSMISSION	DEMAND	Main Grid	Coincident Peak Method (ZCP) - at output of transmission.	5
		230kV & 138kV Radials	Coincident Peak Method (ZCP) - at output of common 230 kV Radials.	5
		138/72kV Substations	Coincident Peak Method (ZCP) - at output of substations.	5
		72kV Radials	Coincident Peak Method (ZCP) - at output of common 72kV radials.	5
DISTRIBUTION	DEMAND	Area Substations - Demand	Coincident Peak Method (ZCP) - at output of substations.	5
		Distribution Mains - Demand	Coincident Peak Method (ZCP) - at output of distribution mains.	5
		Urban Laterals - Demand	Coincident Peak Method (ZCP) - at output of urban laterals.	5
		Rural Laterals - Demand	Coincident Peak Method (ZCP) - at output of rural laterals.	N/A
	CUSTOMER	Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.	5
		Urban Laterals - Customer	Number of urban customers supplied through laterals.	N/A
		Rural Laterals - Customer	Number of rural customers supplied through laterals.	5
		Transformers - Customer	Number of customers supplied through laterals.	N/A
		Services - Customer	Direct to classes which are using services.	N/A
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.	N/A
CUSTOMER SERVICES CUSTOMER CONTRIBUTIONS INTERRUPTIBLE ADJUSTMENT	CUSTOMER	Streetlights - Customer	Direct to Streetlight Class.	N/A
	CUSTOMER	Customer Service	Weighted number of customers.	N/A
	CUSTOMER	Customer Contributions	Direct to classes which made contribution.	N/A
	DEMAND	Interruptible Adjustment	Coincident Peak Method (ZCP).	5

ZCP METHOD

The ZCP (coincident peak) method, allocates costs to rate classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peak. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The NCP-MDD method allocates rate base and expense responsibilities based on the ratio of the class' non coincident peak maximum demand, to the sum of all the class non coincident peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation 2026 Fiscal Test Embedded Cost of Service Study							
Customer Class	Energy Sales GWH	NCP Demand KW	MDD Demand KW	CP Demand KW	NCP Load Factor ¹	MDD Load Factor ²	CP Load Factor ³
Residential	3,299	3,122,761	763,369	664,070	12.06%	49.33%	56.71%
Farms	1,275	795,113	256,933	213,597	18.30%	56.64%	68.14%
Commercial	3,886	1,336,813	637,268	591,678	33.19%	69.61%	74.98%
Power	10,624	1,875,661	1,438,983	1,274,633	64.66%	84.28%	95.14%
Oilfields	4,361	761,546	545,826	510,676	65.37%	91.21%	97.48%
Reseller	1,106	225,036	225,036	196,491	56.12%	56.12%	64.28%
Total	24,551	8,116,931	3,867,416	3,451,144	34.53%	72.47%	81.21%

1 - NCP Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (NCP Demand * 8760)

2 - MDD Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (MDD Demand * 8760)

3 - CP Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (CP Demand * 8760)

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class GENERATION Related Costs 2026 Fiscal Test Embedded Cost of Service Study																							
Customer Class	Load ¹		Load ²	Losses ³		Losses ⁴		Scheduling & Dispatch ³		Regulation & Frequency Response ³		Spinning Reserve ³		Supplementary Reserve ³		Planning Reserve ³		Reactive Supply ³		Grants in Lieu of Taxes ⁵		Interruptible Adjustment ³	
	Demand	Energy		Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy
Residential	19.2%	13.4%	28.3%	21.6%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	22.2%	20.2%	20.2%	20.2%
Farms	6.2%	5.2%	8.5%	7.6%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.7%	6.4%	6.4%	6.4%
Commercial	17.1%	15.8%	24.6%	24.6%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	19.8%	17.9%	17.9%	17.9%
Power	36.9%	43.3%	17.2%	20.6%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	34.8%	31.2%	34.8%	34.8%	34.8%
Oilfields	14.8%	17.8%	18.9%	23.7%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	16.6%	15.2%	15.2%	15.2%
Reseller	5.7%	4.5%	2.4%	2.0%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	3.4%	5.3%	5.3%	5.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹Based on Coincident Peak (ZCP) at the meter.

²Based on actual energy consumption at the meter.

³Based on Coincident Peak (ZCP) & losses.

⁴Based on energy losses.

⁵Based on Sales Revenue.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class TRANSMISSION Related Costs 2026 Fiscal Test Embedded Cost of Service Study				

Customer Class	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
	Demand	Demand	Demand	Demand
Residential	20.2%	14.6%	31.4%	31.4%
Farms	6.4%	4.7%	9.9%	9.9%
Commercial	17.9%	12.8%	28.1%	28.1%
Power	34.8%	53.9%	7.7%	7.7%
Oilfields	15.2%	11.8%	22.4%	22.4%
Reseller	5.3%	2.2%	0.5%	0.5%
Total	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on Coincident Peak (2CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class DISTRIBUTION Related Costs 2026 Fiscal Test Embedded Cost of Service Study														
Customer Class	Area Substations ¹	Distribution Mains ¹		Urban Laterals ¹	Urban Laterals ²	Rural Laterals ¹	Rural Laterals ³	Transformers ⁴	Transformers ⁵	Services ⁶	Instrument Transformers ⁷	Amortization Customer Contributions ⁸	Meters ⁹	Streetlights ¹⁰
		Demand	Demand											
Residential	33.9%	34.0%	25.9%	88.1%	10.4%	44.3%	28.3%	75.0%	31.3%	0.0%	21.6%	57.2%	0.0%	0.0%
Farms	10.7%	10.7%	0.0%	0.0%	18.8%	34.3%	12.3%	10.2%	11.3%	0.6%	29.6%	10.2%	0.0%	0.0%
Commercial	29.4%	29.5%	74.1%	11.9%	19.8%	10.2%	33.2%	11.4%	39.4%	87.1%	33.4%	24.4%	100.0%	100.0%
Power	2.2%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oilfields	23.6%	23.6%	0.0%	0.0%	51.1%	11.2%	26.2%	3.3%	18.0%	1.0%	15.4%	6.9%	0.0%	0.0%
Reseller	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.1%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹Based on Coincident Peak (KCP) & losses.

²Based on the number of urban customers in each customer class. Urban streetlights are based on 6 lights per circuit.

³Based on the number of rural customers in each customer class. Rural streetlights are based on 3 lights per circuit.

⁴Based on Non Coincident Peak (NOP) & losses.

⁵Based on the number of customers with transformer-related equipment in each customer class. Streetlights are based on 6(urban) & 3(rural) lights per circuit.

⁶Based on the number of customers in each customer class supplied through services weighted by installed cost of a service.

⁷Based on the number of customers with transformer-related equipment in each customer class.

⁸Based on customer contributions in each customer class.

⁹Based on the new capital cost of meters and instrument transformers multiplied by the number of customers in the customer class.

¹⁰Direct to the streetlight class.

¹ Based on Coincident Peak (COP) & losses.

² Based on the number of urban customers in each customer class. Urban streetlights are based on 6 lights per circuit.

³ Based on the number of rural customers in each customer class. Rural streetlights are based on 3 lights per circuit.

⁴ Based on Non Coincident Peak (NCP) & losses.

⁵ Based on the number of customers with transformer-related equipment in each customer class. Streetlights are based on 6 (urban) & 3 (rural) lights per circuit.

⁶ Based on the number of customers in each customer class supplied through services weighted by installed cost of a service.

⁷ Based on the number of customers with transformer-related equipment in each customer class.

⁸ Based on customer contributions in each customer class.

⁹ Based on the new capital cost of meters and instrument transformers multiplied by the number of customers in the customer class.

¹⁰ Direct to the streetlight class.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class CUSTOMER SERVICE Related Costs 2026 Fiscal Test Embedded Cost of Service Study						
Customer Class	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
	Customer	Customer	Customer	Customer	Customer	Customer
Residential	20.4%	73.2%	56.0%	87.0%	68.0%	11.8%
Farms	3.8%	15.8%	10.1%	6.0%	12.0%	9.1%
Commercial	27.6%	6.8%	18.0%	6.0%	11.7%	19.0%
Power	23.0%	0.0%	2.3%	0.0%	2.7%	32.2%
Oilfields	24.6%	4.2%	13.5%	1.0%	5.6%	27.1%
Reseller	0.6%	0.0%	0.1%	0.0%	0.1%	0.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on the department responsible's estimate of labour time spent on each customer class.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class																							
GENERATION Related Costs																							
2026 Fiscal Test Embedded Cost of Service Study																							
(\$ Millions)																							
Customer Class	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses	Scheduling & Dispatch		Regulation & Frequency Response		Spinning Reserve		Supplementary Reserve		Planning Reserve		Reactive Supply		Grants in Lieu of Taxes		Interruptible Adjustment		
				Demand	Energy		Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand
Residential	685.1	325.9	47.6%	83.0	171.5	14.1	19.2	2.7	1.7	5.0	7.5	9.4	4.2	7.7	-	-	-	-	-	-	-	-	
Farms	211.7	116.0	54.8%	26.7	66.3	4.3	6.7	0.8	0.5	1.6	2.4	3.0	1.3	2.3	-	-	-	-	-	-	-	-	
Commercial	572.7	344.1	60.1%	73.9	202.1	12.3	21.9	2.4	1.5	4.5	6.7	8.3	3.7	6.9	-	-	-	-	-	-	-	-	
Power	928.8	801.7	86.3%	159.2	552.4	8.6	18.3	4.6	2.9	8.6	12.9	16.1	7.2	10.8	-	-	-	-	-	-	-	-	
Oilfields	510.1	349.8	68.6%	63.8	226.7	9.4	21.1	2.0	1.3	3.8	5.7	7.1	3.2	5.7	-	-	-	-	-	-	-	-	
Reseller	108.2	94.3	87.2%	24.5	57.5	1.2	1.7	0.7	0.7	1.3	2.0	2.5	1.1	1.2	-	-	-	-	-	-	-	-	
Total	3,016.4	2,031.7	67.4%	431.1	1,276.5	50.0	89.0	13.2	8.4	24.8	37.1	46.4	20.7	34.6	-	-	-	-	-	-	-	-	

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class											
TRANSMISSION Related Costs											
2026 Fiscal Test Embedded Cost of Service Study											
(\$ Millions)											
Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid		230 kV Radials		230/138 kV Substations		138 kV Lines Radials	
				Demand		Demand		Demand		Demand	
Residential	685.1	72.3	10.6%	44.6	9.6	6.5	11.5				
Farms	211.7	23.0	10.9%	14.2	3.1	2.1	3.6				
Commercial	572.7	64.3	11.2%	39.6	8.4	5.9	10.3				
Power	928.8	116.8	12.6%	76.9	35.5	1.6	2.8				
Oilfields	510.1	54.3	10.7%	33.7	7.7	4.7	8.3				
Reseller	108.2	13.6	12.5%	11.8	1.5	0.1	0.2				
Total	3,016.4	344.3	11.4%	220.8	65.8	20.9	36.8				

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class DISTRIBUTION Related Costs 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)													
Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals	
				Demand	Total	Demand	Total	Demand	Total	Demand	Total	Demand	Total
Residential	685.1	207.9	30.4%	18.1	51.7	4.8	38.1	35.0	14.8	21.1	14.6	-	-
Farms	211.7	60.3	28.5%	5.7	16.3	-	-	27.1	6.4	2.9	(5.6)	0.0	1.1
Commercial	572.7	151.3	26.4%	15.7	44.9	13.8	5.2	8.1	17.3	3.2	15.7	1.4	2.6
Power	928.8	48	0.5%	1.2	3.3	-	-	-	-	-	-	0.2	0.1
Oilfields	510.1	97.8	19.2%	12.6	36.0	-	-	17.3	13.7	0.9	7.7	0.0	0.7
Reseller	108.2	0.2	0.2%	0.2	-	-	-	-	-	-	-	0.0	0.0
Total	3,016.4	522.3	17.3%	53.6	152.2	18.6	43.3	79.0	52.2	28.1	32.3	1.7	10.8
													16.7

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class CUSTOMER SERVICE Related Costs 2026 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
Residential	685.1	78.9	11.5%	2.0	17.9	0.7	25.3	32.3	0.7
Farms	211.7	12.3	5.8%	0.4	3.9	0.1	1.7	5.7	0.5
Commercial	572.7	13.0	2.3%	2.7	1.7	0.2	1.7	5.6	1.1
Power	928.8	5.5	0.6%	2.3	0.0	0.0	0.0	1.3	1.9
Oilfields	510.1	8.2	1.6%	2.4	1.0	0.2	0.3	2.6	1.6
Reseller	108.2	0.1	0.1%	0.1	0.0	0.0	0.0	0.0	0.1
Total	3,016.4	118.0	3.9%	9.9	24.4	1.3	29.0	47.4	5.9

Schedule 7.0: Customer Data for Rate Design

Customer Data					
2026 Fiscal Test Embedded Cost of Service Study					
Customer Class	Average Annual # of Accounts	Annual Revenue (\$)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)	
Residential	422,379	670,570,600	3,298,700	-	
Farms	57,594	201,046,500	1,274,900	1,876,160	
Commercial	65,401	598,360,100	3,886,200	10,939,342	
Power	111	947,568,000	10,623,600	20,985,091	
Oilfields	18,806	494,979,600	4,361,000	9,187,921	
Reseller	3	103,900,000	1,106,400	2,190,447	
Total	564,294	3,016,424,800	24,550,800	45,178,961	

2027 FISCAL TEST EMBEDDED COST OF SERVICE STUDY

PREPARED BY:

Pricing & Costing

of

Pricing & Energy Forecasting

Submitted On:

December 22, 2025

❖ BASED ON 2026-27 FISCAL BUSINESS PLAN FORECASTED FINANCIAL STATEMENTS AND SCHEDULES

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I. INTRODUCTION

A. Purpose

The SaskPower 2027 Fiscal (2027F) Test Cost of Service Study provides an in-depth, detailed account of the annual cost to serve each of SaskPower's customer classes at the end of the forecasted fiscal year (ending March 31, 2027). The primary purpose is to provide an indication of the extent by which revenues contributed from a particular class, recover the allocated costs of serving that customer class.

To remain viable, SaskPower must be given the opportunity to recover its incurred costs of providing electric service to its various classes of customers. Cost of service is usually defined to include all a utility's operating expenses, plus a reasonable return on its investment ("rate base") devoted to the service of the rate paying public. These stakeholders and their interests are as follows:

1. **Saskatchewan Rate Review Panel (SRRP):** The Saskatchewan Rate Review Panel is interested in assuring that SaskPower only includes costs and returns that are related to SaskPower's core business. They are also interested in assuring that SaskPower applies methodologies that are reasonable and acceptable. The SRRP also relies on the opinion of an external consultant to report on the reasonableness of the embedded Cost of Service Study.
2. **SaskPower Management / Executive / Board:** SaskPower's Executive, Management, and Board are interested in ensuring that the corporation's financial targets are achieved. The cost of service model is vital to the development of rates and achieving SaskPower's revenue requirement.
3. **Customers:** The cost of service provides documentation to these stakeholders in terms of how much of the cost to provide them with service is recovered through the rates they pay.

B. Scope

A Cost of Service Study is a study of the costs incurred by SaskPower in producing, transmitting, and distributing electricity to its customers, by customer class, in relation to revenues collected from each class under existing rates. For this report the costs analyzed are the forecasted "embedded" costs of the existing plant and expenses in the fiscal "**Test year**" of **2027**.

NorthPoint Energy Solutions is a SaskPower owned subsidiary company. The financial assets and expenses from this subsidiary have been included in this year's cost of service study. Best

practices from other utilities across Canada have shown it is prudent to rate payers for a utility to include subsidiary financial results in years when the subsidiary achieves a net gain. In years of net loss, subsidiaries will not be included in the Cost of Service Study.

C. Objectives

Cost of service studies are among the basic tools of ratemaking. While non-cost concepts and principles can modify the cost-based standard, cost of service methodology remains the primary factor in determining the reasonableness of rates. SaskPower's key objectives of the cost-of-service study and resulting rate design are as follows:

1. Meeting Revenue Requirement
2. Fairness and Equity
3. Economic Efficiency
4. Conservation of Resources
5. Simplicity and Administrative Ease
6. Stability and Gradualism

Meeting Revenue Requirement

Meeting the revenue requirement suggests that SaskPower's customer rates are designed with the purpose to provide sufficient revenue to cover both the utility's forecasted annual costs and return on rate base. Annual costs and the return on rate base are further explained within Step 1 of the Identification section of the cost of service methodology.

Fairness and Equity

Fairness and equity imply that SaskPower's cost of service methodology and rate design is applied to the various customer classes, based on cost behaviour drivers and cost causality, while projecting no undue discrimination between customers.

Economic Efficiency

Economic efficiency refers to SaskPower's objective of utilizing assets and expenses in a manner that is operationally effective for developing a power system, while the rates charged for electrical service provide the appropriate price signals to customers that will allow SaskPower to maintain a power system that continues to be efficient over time.

Conservation of Resources

Conservation of resources relies on asset and cost allocations that provide appropriate price signals to consumers, so that they will utilize power in a reasonable manner while considering SaskPower's cost of providing power and the value placed on that power by the various customer classes.

Simplicity and Administrative Ease

Simplicity and administrative ease objectives for ratemaking rely on concepts of allocation that are logical, transparent to stakeholders and customers, and easily implementable.

Stability and Gradualism

Stability and gradualism objectives aspire to employ cost allocations and rate-making standards that are steady over longer periods. Stability and gradualism goals avoid non-typical volatility of rates to any customer classes at any given time.

Since the above objectives do not always agree with the concept that service should be provided on a cost basis, SaskPower must use judgement and the advice of our shareholder and Cabinet as to the appropriate courses of action.

D. Cost of Service Methodology Changes

The latest review of SaskPower's cost of service and rate design methodology occurred in 2023 (January - June). The review was conducted by Elenchus Research Associates, from Toronto, Ontario.

Elenchus filed its final report on June 30, 2023, which stated, in their view, SaskPower's current cost allocation methodology is consistent with accepted rate making principles and practices, is consistent with methodologies commonly used by other electric utilities, and is reflective of SaskPower's operational circumstances, with some recommendations for enhancements:

1) Removal of the coincident peak allocation methodology (Bary correction) in rate design.

SaskPower previously employed an adjustment when designing rates for classes of customers where customers load factors and coincidence factors varied. Within these classes of customers, high load factor customers typically have higher coincidence factors, meaning they consume more electricity consistently, and particularly at system peak, resulting in more capacity costs.

The Bary correction's main purpose was to shift some of the demand-related costs to be recovered through the energy charge. This adjustment was also beneficial in being more equitable with cost causality, where customers were being billed for costs that they were responsible for causing.

The unintended effect was a distorted price signal for energy and demand charges, where inflated energy charges and lower demand charges provided an incorrect price signal for customers to defect from the grid and/or self-generate, to avoid the higher

energy charges. These signals gave an inadvertent effect of shifting demand costs from self-generation customers to other SaskPower customers who did not create the burden of these costs.

Starting in 2022, SaskPower gradually began phasing out the Bary correction within its rate design and Elenchus supports this change.

2) Further investigate the deployment of Time of Use (TOU) rates as a means to managing the demand with the intention of minimizing the need for new capacity.

TOU rates have been implemented by various utilities in a response to providing an accurate price signal to customers for consuming electricity at varying times of a day, and/or season with the intention of reducing generation costs which cascade to lower utility costs and ultimately, lower bills for customers. The purpose of TOU rates is to influence customers to change their electricity consumption behaviours from high-cost periods to low-cost periods, which allows a power utility to reduce its total costs during peak periods or during periods of higher expense incurred periods.

For TOU rates to be utilized, more Advanced Metering Infrastructure (AMI) needs to be deployed including proper metering, and billing systems, along with appropriate economic differentials in marginal cost that utilities can present to entice customers to shift their demand and reduce a utility's average cost of power.

With SaskPower's inherent system load factor of 75% at this current time, and projected new load relatively being flat, there is minimal opportunity for SaskPower to shift load. Elenchus recommended a continuation with current rate structure, but if conditions change and marginal costs increase, SaskPower should consider a move to TOU rates.

3) Rate Alignment options

SaskPower employs a typical rate structure for all classes that aligns rate components (e.g. fixed charges, demand charges and energy charges) with their corresponding classified costs (customer-related, demand-related and energy-related) where it is feasible, based on metering technology availability, while avoiding unintended consequences like rate shock.

As mentioned previously, Elenchus expressed concerns of the Bary correction's inherent misalignment of revenue and cost-driven price signals that motivated self-generation/grid defection that shifted the burden to other SaskPower customers who did not incur those costs. This violates SaskPower's objectives of fairness/equity, and economic efficiency, and can lead to stranded assets for the utility.

Implementation of demand charges for all customer classes utilizing coincident peak demand is a potential option but is not economically practical for low demand customers as it requires Advanced Metering Infrastructure (AMI) equipment. Also, price signals can be difficult for customers to respond to appropriately, especially if they have no lead time to reduce their demand.

Another option Elenchus provided would be to assign a portion of demand-related costs within a basic monthly charge. Although this would increase revenue and bill stability, assigning demand-related costs within the basic monthly charge would be inequitable to customers with lower consumption and demand such as low-income customers and seasonal customers.

SaskPower's current rate methodology for customers without demand charges, such as the Residential class, does recover demand-related costs within the energy charge, and follows a standardized practice across utilities. Elenchus acknowledges that a change from this practice would provide an inappropriate price signal to customers, particularly in scenarios where costs derived from consumption and demand are greater than variable revenue recovered from the customer.

After reviewing the options SaskPower has available, Elenchus recommended that SaskPower continue to utilize its current rate design practices for customer classes without demand charges, while continuing to identify its rate structure once AMI billing data has been implemented.

E. Financial Reporting Changes affecting 2026

Minimal financial reporting changes were made, which impact the 2027 Fiscal Test Forecasted financial information. The following are of note:

- 1) The Streetlight class is reported financially within the Commercial class and the Power – Contract class is being reported financially within the Power class. These amendments align to SaskPower's current financial reporting structure.
- 2) As of April 1, 2025, the provincial government directed SaskPower to stop collecting the Federal Carbon Tax from its customers.

Previously, as of April 1, 2019, the federal government implemented a Carbon Tax on fossil fuel emissions based on their carbon pollution pricing system, retroactive to January 1, 2019. The Federal Carbon Tax is based on predetermined emission thresholds set by the federal government on an annual calendar basis.

Until April 1, 2025, SaskPower elected to recover the Federal Carbon Tax through separate rate riders based on customers' energy consumption (kWh), rather than incorporating it into its published rates. As a result of this approach, expenses and revenue related to the carbon tax have never been included in the Cost-of-Service Study. Consequently, the suspension of carbon tax collection does not affect the results of the Cost-of-Service Study.

- 3) All Purchased Power Agreement (PPA's) assets are reported as a separate line item within the Cost-of-Service report, functionalized within Generation.
- 4) Organizational realignment of various Business units occurred throughout 2024 as follows:
 - SaskPower has consolidated NorthPoint, Generation, Transmission and Distribution into one business unit called Operations. Similarly, Asset Management, Technology & Security, and Finance have been consolidated under one business unit called Strategy, Technology & Finance. Procurement and Customer Experience (previously called Customer Services) have also been combined into a business unit called Customer Experience and Procurement. Although these units are now reporting from different areas, their rate base and expenses are still functionalized and classified in the same manner as they were previously.

F. Calculation of the Return on Rate Base

The Return on Rate Base (RORB) is the return, expressed as a percentage, which SaskPower will earn on the net book value of its assets required to produce, transmit and distribute electricity to its customers, after expenses. SaskPower's RORB is directly tied to its Return on Equity (ROE) performance and is based on achieving its targeted ROE of 8.5%.

The system RORB is calculated based on SaskPower's actual (or forecasted) revenues, expenses, and rate base for the fiscal year. The tables below show the calculation of SaskPower's RORB derived from the 2027 Fiscal Test Cost of Service:

SaskPower Return on Rate Base Inputs/Supporting Calculations as of March 31, 2027
2027 Fiscal Test Embedded Cost of Service Study
(\$ Millions)

Indicator	Item:	2027 Fiscal Test	Calculation Details:
	<u>From SaskPower's Cost of Service</u>		
a)	Total Rate Base	13,510.0	
b)	Electricity Sales Revenue	3,206.8	
c)	Other revenues (incl. Export & Electricity Trading)	<u>244.1</u>	
d)	Total Sales Revenue	<u>3,450.9</u>	b + c
e)	Total Expenses	<u>2,813.7</u>	
f)	Operating Income Before Finance Charges	<u>637.2</u>	d - e
g)	Finance Charges	<u>458.0</u>	
h)	Operating Income	<u>179.2</u>	f - g
i)	Return on Rate Base - Finance Charges	3.4%	g / a
j)	Return on Rate Base - Return	<u>1.3%</u>	h / a
k)	Total Return on Rate Base	<u>4.7%</u>	f / a
	<u>From SaskPower's Financial Statements</u>		
l)	Long Term Debt	10,157.5	
m)	Current Portion of Long Term Debt	(300.0)	
n)	Finance Lease Obligations	830.4	
o)	Current Portion of Lease Obligations	(62.4)	
p)	Short Term Advances	1,259.1	
q)	Debt Retirement Funds	(1,121.4)	
r)	Cash & Cash Equivalents	<u>52.8</u>	
s)	Total Debt	<u>10,816.0</u>	l + m + n + o +
t)	Retained Earnings	2,244.8	
u)	Equity Advances	593.0	
v)	Total Equity	<u>2,837.8</u>	t + u
w)	Total Debt & Equity	<u>13,653.8</u>	s + v
x)	Debt %	79.2%	s / w
y)	Equity %	20.8%	v / w

SaskPower 2027 Fiscal Test Return on Rate Base as of March 31, 2027
2027 Fiscal Test Embedded Cost of Service Study
(\$ Millions)

	Amount	Capital Structure	Cost of Capital	Component Weighted Cost of Capital
Debt	10,816.0	79.22% *	4.28%	= 3.39%
Equity	2,837.8	20.78% *	6.38%	= 1.33%
Total	13,653.8	Return on Rate Base		4.72%

Please note that within the Cost-of-Service Return on Equity (ROE) calculation, unlike within the ROE calculation within SaskPower's Financial Statements, equity earnings are not included.

G. Cost of Service to Business Plan Reconciliation

Due to differences between IFRS accounting standards and the National Association of Regulatory Utility Commissioner's (NARUC) electric utility cost allocation standards, an Income Statement and a Balance Sheet reconciliation that highlights the difference between the two is included below:

Fiscal Test Income Statement - Cost of Service to Forecasted Business Plan Financial Statements Reconciliation
(\$ Millions)

	2027 Fiscal Test		
	Income Statement	Adjustment	Cost of Service
REVENUE			
Saskatchewan Sales	\$3,106.5	\$100.32 *	\$3,206.8
Federal Carbon Revenue	\$0.0	\$0.0	\$0.0
Export + Electricity Trading	\$64.7	(\$64.7)	\$0.0
Other Income (Does Not Include SPI Equity Earnings)	\$179.4	(\$179.4)	\$0.0
Total Revenue	\$3,350.6	(\$143.8)	\$3,206.8
EXPENSES			
Fuel & Purchased Power			
Fuel	\$640.3		\$640.3
Purchased Power	\$308.1		\$308.1
Federal Carbon Charge Expense	\$0.0	\$0.0	\$0.0
Total Fuel and Purchased Power	\$948.4	\$0.0	\$948.4
Less Export & Net Electricity Trading Revenue		(\$64.7)	(\$64.7)
Total Fuel & Purchased Power After Export Revenue	\$948.4	(\$64.7)	\$883.7
Total OM&A	\$986.6		\$986.6
Total Depreciation & Other Expenses	\$765.5		\$765.5
Finance Charges	\$458.0	(\$458.0)	\$0.0
Total Taxes	\$113.2		\$113.2
Total Other Income	(\$179.4)	(\$179.4)	(\$179.4)
Total Expenses	\$3,092.3	(\$702.1)	\$2,569.6
Operating Income	\$258.3	\$558.3	\$637.2
Rate Base			\$13,510.0
Return on Rate Base			4.72%

Reconciliation to Audited Financial Statements:

Operating Income for the Cost of Service before Adjustments	\$637.2
add: Federal Carbon Tax Revenue	\$0.0
less: Finance Charges	(\$458.0)
Foreign Exchange Gains/Losses	\$0.0
Federal Carbon Charge Expense	\$0.0
Operating Income Before Adjustments	\$179.2
less: Adjustment to Full Year Revenue due to Timing of Rate Application *	(\$100.3)
Net Income as per the Audited Financial Statements	\$78.9

* Saskatchewan Sales Revenue was adjusted in the Cost of Service model to include the full 12 months of the proposed revenue lift for the fiscal year, reflecting an effective date of April 1st, 2026.

** numbers may differ due to immaterial rounding

Fiscal Base Balance Sheet - Cost of Service to Forecasted Business Plan Financial Statements Reconciliation
(\$ Millions)

Reconciliation to Audited Financial Statements:	2027 Fiscal Test
Rate Base from the Cost of Service before Adjustments <i>(see Schedule 1.0)</i>	\$13,510.0
add: Current Assets Net of Inventories, Prepaid, & Risk Mgmt Assets	\$653.5
Equity Investments	\$0.0
Debt Retirement Funds	\$1,121.4
Construction in Progress	\$2,084.2
Risk Management Assets (unrealized)	\$0.0
less: Working Capital Adj	(\$137.5)
Total Assets as per the Audited Financial Statements *	\$17,231.6

* numbers may differ due to immaterial rounding

II. SUMMARY OF RESULTS

Tables 1, 2, and 3 outline the summary results from the 2027 Fiscal Test Cost of Service Study.

- **Table 1 – Summary of Functionalized Revenue Requirement**
This table identifies the cost of service by function (Generation, Transmission, Distribution, and Customer Service).
- **Table 2 – Summary of Classified Revenue Requirement**
This table identifies the cost of service by billing component for each customer class. The breakdown mimics the rate structure for all customer classes.
- **Table 3 – Summary of Revenue-to-Revenue Requirement Ratios**
This table displays the breakdown of Revenue-to-Revenue Requirement Ratio by customer class.

Table 1 – Summary of Functionalized Revenue Requirement

Summary of Functionalized Revenue Requirement by Customer Class 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Customer Class	Total Company (\$)	Generation		Transmission		Distribution		Customer Service	
		(\$)	(%)	(\$)	(%)	(\$)	(%)	(\$)	(%)
Residential Farms	703.5	339.8	48.3%	70.4	10.0%	226.0	32.1%	67.3	9.6%
	221.3	123.5	55.8%	22.9	10.3%	64.5	29.1%	10.4	4.7%
Commercial Power	584.1	348.9	59.7%	60.8	10.4%	163.0	27.9%	11.4	2.0%
	1,033.0	910.2	88.1%	112.3	10.9%	5.4	0.5%	5.1	0.5%
Oilfields Reseller	548.4	377.5	68.8%	54.4	9.9%	109.2	19.9%	7.2	1.3%
	116.6	102.4	87.9%	13.8	11.9%	0.2	0.2%	0.1	0.1%
Total	3,206.8	2,202.3	68.7%	334.6	10.4%	568.3	17.7%	101.6	3.2%

Table 2 – Summary of Classified Revenue Requirement

Summary of Classified Revenue Requirement by Customer Class 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)						
Customer Class	Total Company (\$)	Demand Related (\$)		Energy Related (\$)		Customer Related (\$)
			(%)		(%)	(%)
Residential	703.5	302.9	43.1%	207.6	29.5%	193.0
Farms	221.3	104.2	47.1%	80.5	36.4%	36.6
Commercial	584.1	278.7	47.7%	234.7	40.2%	70.8
Power	1,033.0	368.1	35.6%	659.5	63.8%	5.4
Oilfields	548.4	246.6	45.0%	274.3	50.0%	27.5
Reseller	116.6	50.7	43.5%	65.7	56.3%	0.2
Total	3,206.8	1,351.2	42.1%	1,522.2	47.5%	333.4
						10.4%

Table 3 – Summary of Revenue-to-Revenue Requirement Ratios

Summary of Revenue to Revenue Requirement Ratios 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)			
Customer Class	Revenue (\$)	Revenue Requirement (\$)	Revenue to Revenue Requirement Ratio
Residential	694.8	703.5	0.99
Farms	213.1	221.3	0.96
Commercial	603.9	584.1	1.03
Power	1,047.5	1,033.0	1.01
Oilfields	535.6	548.4	0.98
Reseller	111.9	116.6	0.96
Total (System)	3,206.8	3,206.8	1.00

III. COST OF SERVICE METHODOLOGY

The study follows a five-step process:

- The first step is to **identify** in detail the accounting costs that are to be allocated to customer classes.
- The second step is to **functionalize** the costs between generation, transmission, distribution, and customer services functions.
- The third step is to **classify** each set of functionalized costs into demand, energy, and customer components.
- The fourth step is to **allocate** the functionally classified costs among the several customer classes.
- The fifth step is to **compare** between the allocated costs and the revenues collected from the customer classes to arrive at the revenue to cost ratios.
- The sixth step is to **create** ideal rates for each class of customers so that the appropriate amount of revenue is collected based on the class's costs.

STEP 1: IDENTIFICATION

The initial step is to identify the accounting costs to be included in the Cost-of-Service Study. SaskPower's Finance Business Unit supplies the 2027 Fiscal Year End Consolidated Financial Summary.

Three types of accounts are separately identified in detail:

1. Rate Base Items – investments and liabilities as reported in SaskPower's Balance Sheet. Please refer to **Schedule 1.0** for summary of these items as well as the forecasted data for the 2027 Fiscal Test Year. Data is reported for the year end in the following categories:

- Plant in Service
- Accumulated Depreciation
- Allowance for Working Capital
- Inventories
- Other Assets

Plant in Service is reported in more detail by function: Generation - by type of generation, Transmission - by voltage level, Distribution Plant - by type of plant, and General & Intangible Plant - by primary usage (unused land, buildings, office furniture and equipment, vehicles & equipment, computer development & equipment, communication, protection & control, and tools and equipment).

Contributions in Aid of Construction were previously netted against Fixed Assets as part of the Rate Base and amortized over the estimated service life of the related asset. The amortization of these contributions was netted against Depreciation Expense under GAAP. However, with the adoption of IFRS accounting standards in 2011, Contributions in Aid of Construction is recognized immediately as Other Income when the related fixed asset is available for use.

2. Revenue Requirement – this is a calculation of annual costs (from SaskPower’s Income Statement) plus the Return on Rate Base (calculated as Rate Base multiplied by the system average Return on Rate Base percentage). The system average Return on Rate Base is equal to total revenue minus total expenses divided by the total rate base. Please refer to **Schedule 1.0** for a summary of these items as well as the forecasted data for the 2027 Fiscal Test Year. Data is reported for the year end in the following categories:

- Fuel
- Purchased Power
- Export Revenue (Credit)
- Operating, Maintenance, & Administration (OM&A)
- Depreciation and Depletion
- Corporate Capital Tax
- Grants In Lieu of Taxes
- Miscellaneous Tax
- Other Operating Revenues (Credit)
- Return on Rate Base (Rate Base multiplied by the system average Return on Rate Base)

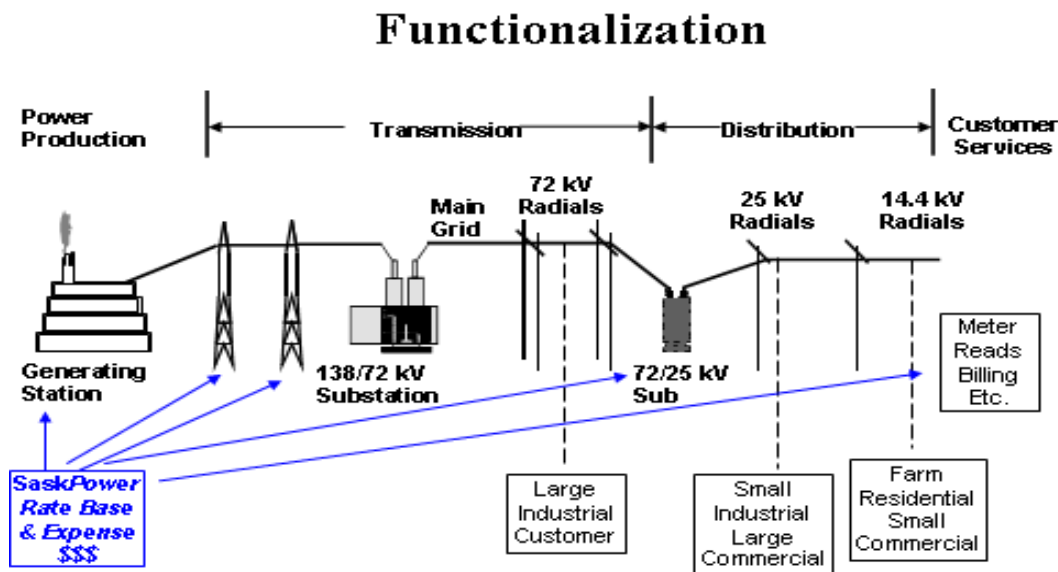
3. Revenue Items - annual domestic sales revenues as reported on SaskPower’s Income Statement. For forecast (Test) years, the SaskPower Load & Revenue Forecasting department provides a projection of net sales within Saskatchewan. **Schedule 7.0** provides a summary by customer class of the actual revenues for the 2027 Fiscal Test Year.

STEP 2: FUNCTIONALIZATION

The second step is to functionalize all accounting costs, in terms of plant and expenses into the major functions of SaskPower's integrated electric system. Please refer to **Figure 1** for a schematic of the process. Rate base and expenses are assigned to the following functions and sub functions:

1. Generation Load Losses Scheduling & Dispatch Regulation & Frequency Response Spinning Reserve Supplementary Reserve Planning Reserve Reactive Supply Grants in Lieu of Taxes	3. Distribution Area Substations Distribution Mains Urban Laterals Rural Laterals Transformers Services Instrument Transformers Meters Streetlights Customer Contributions
2. Transmission Main Grid 230kV & 138kV Lines Radials 138kV/72kV Substations 72kV Lines Radials	4. Customer Service Metering Services Meter Reading Billing & Customer Accounts Customer Collecting Service & Support Customer Strategy & Planning

Figure 1: Functionalization Schematic



Please refer to **Schedules 2.00 through to 2.36** for the functionalization of the financial accounting details. A summary of the functionalization methodology is summarized below for rate base and revenue requirement which includes annual expense items from the income statement and return on rate base.

1. Rate Base Items

1.1 - Plant in Service & Accumulated Depreciation

- **SaskPower Generation, Transmission, and Distribution:**
All the rate base accounts are functionalized based on the plant designation; generation plant is functionalized entirely to the generation function; transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for Wind Projects is included within SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.
- **Coal Reserves:**
SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

-
- **Shand Greenhouse:**
The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.
 - **Purchased Power Agreements:**
The assets associated with Purchased Power Agreements are functionalized to generation.
 - **Meters and Instrument Transformers:**
Meters and instrument transformers are included in the meters and instrument transformers sub-function within distribution.
 - **General Plant - Unused Land:**
The functionalization and sub-functionalization of unused land is done using OM&A expense.
 - **General Plant – Right of Use Land:**
The functionalization and sub-functionalization of right-of-use land is done using OM&A expense.
 - **General Plant – Buildings:**
The functionalization and sub-functionalization of the SaskPower head office building and all other buildings is done using OM&A expense.
 - **General Plant – Right of Use Buildings:**
The functionalization and sub-functionalization of right-of-use buildings is done using OM&A expense derived from buildings, excluding Head Office, Research & Development, Storage and Residential Buildings.
 - **General Plant - Office Furniture & Equipment:**
The functionalization and sub-functionalization of office furniture and equipment utilizes OM&A expense for buildings.
 - **General Plant - Vehicles & Equipment:**
The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit centre. The asset values for vehicles and equipment are then prorated to sub-functions within each function using OM&A expense.

- **General Plant - Computer Development & Equipment:**

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) are functionalized on an application-by-application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using OM&A expense.

- **General Plant - Communication, Protection & Control Equipment:**

Communication, Protection & Control Equipment is functionalized to generation, transmission, distribution, and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

- **General Plant - Tools & Equipment:**

The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using OM&A expense.

1.2 - Allowance for Working Capital

- The allowance for working capital is consistent with Cost-of-Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working capital is calculated as 12.5% of the sum of OM&A expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.3 - Inventories

- SaskPower accounting records summarize inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within the generation, transmission and distribution functions using OM&A expense.

1.4 - Other Assets

- Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

- **Natural gas / coal-related:**
Functionalized to generation.
- **Employee-related:**
Functionalized using head count by Business Unit / Support Group.
- **Insurance expense-related:**
Functionalized using information provided from SaskPower's risk management staff.
- **Miscellaneous:**
Prorated to sub-functions within each function using OM&A expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below:

2.1 - Fuel Expense SaskPower Units

- The fuel expense for SaskPower units is functionalized 100% to generation.

2.2 - Purchased Power and Import

- The purchased power expense is functionalized 100% to generation.

2.3 - Export & Net Electricity Trading Revenue

- Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.4 - Operating, Maintenance & Administration (OM&A) Expense

- **Power Production Business Unit:**
The OM&A expenses for the Power Production Business Unit and Purchased Power Agreements (PPAs) are functionalized to Generation.
- **Transmission & Distribution Business Unit:**
A small amount of the Transmission and Distribution Business Unit's OM&A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the OM&A expense for the Business Unit is split to transmission and distribution using cost centre reports.

-
- Transmission OM&A is sub-functionalized by separating transmission OM&A expense into line and station-related functions. The line-related OM&A is sub-functionalized to main grid, 230 & 138 kV radials, & 72 kV radials using the transmission line assets plant in service by sub-function. The station-related OM&A expense is sub-functionalized using the station assets plant in service by sub-function.
 - Distribution OM&A is functionalized to distribution and customer services using a combination of staff input and detailed cost centre OM&A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions.
 - Metering Services OM&A was moved from Customer Services to Transmission & Distribution in 2013 but is still functionalized to Customer Services.
- **Customer Services Business Unit:**
The OM&A expense for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre OM&A reports.
 - **Customer Services - Bad Debt Expense:**
The Bad Debt expense is assigned to the customer collections sub-function within the Customer Services function.
 - **President / Board:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.
 - **Corporate & Financial Services:**
Functionalized based on employee head count by Business Unit and Support Group.
 - **Corporate & Financial Services – Insurance Premiums & Insurable Losses:**
Functionalized based on breakdown from SaskPower's risk management & insurance department staff.
 - **Asset Strategy & Planning:**
Asset Strategy & Planning was previously called Asset Management, Planning & Sustainability. It is made up of four cost centres: Generation Asset Management

and Supply Planning, Transmission Asset Management and Planning, Distribution Asset Management and Planning, and Environment. The Planning cost centres are assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Environment cost centre moved to Resource Planning from Human Resources in 2015 and is allocated based on an employee analysis which was done by SaskPower Environment department staff. The Shand Greenhouse is embedded within the Environment cost centre and is functionalized to Generation.

- **Carbon Capture & Storage (CCS):**
The OM&A expense for CCS is embedded within the Power Production business unit and is functionalized to Generation.
- **Small Modular Reactors (SMR) Consortium:**
The OM&A expense for SMR is embedded within the Asset Strategy & Planning business unit and is functionalized to Generation.
- **General Council / Land:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.
- **Safety:**
Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the OM&A sub-functionalization within each function.
- **Technology & Security (formerly Corporate Information & Technology):**
Technology & Security OM&A expense is separated into personal computer-related and Business Unit-related functions. The personal computer-related function is functionalized using employee headcount. The Business Unit-related function is functionalized using information from the cost centre report. Sub-functionalization is completed using OM&A within each function.
- **Human Resources:**
Functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function.
- **Commercial & Industrial Operations:**
Commercial & Industrial Operations is department made up of three cost centres: Coal Combustion Products, Fuel Supply and NorthPoint. The Customer Relations

cost centre was previously located here but has been since relocated back to Customer Services and continues to be functionalized to Customer Service. Coal Combustion, along with Individual Purchased Power cost centre was recently relocated to Finance but is being tracked and reported in the Power Production business unit and continues to be functionalized to Generation. The Fuel Supply cost centre was previously reported in Resource Planning and continues to be functionalized to Generation. NorthPoint previously was reported in Operations and continues to be functionalized to Generation.

- **Procurement & Supply Chain**

Procurement & Supply Chain is made up of three cost centres: Supply Chain, Properties & Shared Services, and Contract Management. Supply Chain and Properties & Shared Services are functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function. Contract Management is functionalized to Generation. The Logistics area was moved to Procurement & Supply Chain in 2015 from Distribution; however, based on Logistics' close relation to Distribution, their OM&A is still being calculated and functionalized within Distribution.

2.5 - Depreciation & Depletion

- The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.6 - Corporate Capital Tax

- Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.7 - Grants in Lieu of Taxes

- Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.8 – Miscellaneous Tax

- The miscellaneous tax expenses have been grouped into the following categories using cost centre reports:
 - **Power production-related:**
Functionalized to generation.
 - **Corporate-related:**
Functionalized using total OM&A expense.

2.9 - Other Income

- Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.
 - **Customer services payment income:**
Assigned to the billing, customer accounts and collections sub-functions within customer services.
 - **Meter reading income:**
Assigned to the meter reading sub-function within the customer services function.
 - **Transmission-related income:**
Assigned to sub-functions within the transmission function using transmission OM&A expense.
 - **Distribution-related income:**
Assigned to sub-functions within the distribution function using distribution OM&A expense.
 - **Miscellaneous Other Income:**
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.
 - **Customer Contribution Revenue**
As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.
 - **Green power premium:**
Assigned to the load and losses sub-functions within generation using fuel expense.
 - **Flyash & Wind Power Sales:**
Assigned to the load and losses sub-functions within generation using fuel expense.

- **CO2 Sales & Penalties:**
Assigned to the load and losses sub-functions within generation using fuel expense.
- **Renewable Energy Credits:**
Assigned to the load and losses sub-functions within generation using fuel expense.

2.10 - Return on Rate Base

- The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

STEP 3: CLASSIFICATION

The classification process splits the functionalized costs into the parameters of service, which are:

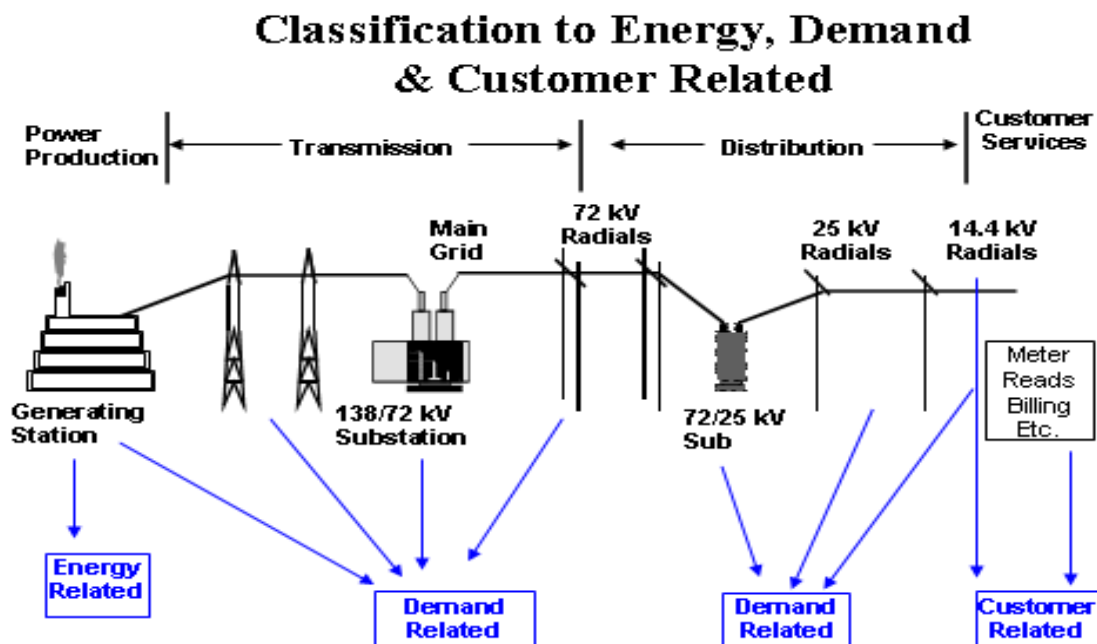
Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission, and distribution systems.

Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.

Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

Figure 2 below presents a schematic of the classification process.

Figure 2: Classification Schematic



A discussion of the classification of each of the functionalized costs is as follows:

- **Generation:**

SaskPower generation rate base and expense is classified as either demand or energy-related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Average & Excess Demand method (AED), based on the NARUC Electric Utility Cost Allocation manual. The rationale behind AED is that a utility's average annual demand is required to meet its energy requirements, and any demand more than that average is required to meet its peaking requirements.

The assets and expenses associated with Purchased Power Agreements (PPAs) are classified to demand and energy using the capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation

operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The expenses and income associated with fly-ash sales (now called Coal Combustion Products) are classified as energy-related.

The classification of all wind generation rate base and expenses are also classified to energy and demand using the Average & Excess Demand method (AED). This is a change from previous years when SaskPower planning staff classified the wind units based on planning studies regarding the capacity value of wind generation.

Diesel units continue to be classified as 100% to demand.

- **Coal Reserves:**

SaskPower coal reserves are classified as energy-related.

- **Shand Greenhouse:**

The Shand Greenhouse assets, OM&A and depreciation expenses are classified using the classification of all SaskPower generation.

- **NorthPoint:**

The OM&A expense and other revenue associated with NorthPoint are classified 100% as energy-related.

- **Transmission:**

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% as demand-related.

- **Distribution:**

Substations are classified 100% as demand-related costs. Three phase feeders are classified 100% as demand-related costs.

Both urban and rural single-phase primary lines are classified 30% to demand-related and 70% to customer-related costs. Line transformers are classified 65% to demand-related and 35% to customer-related cost based upon Minimum System Method (MSM). As indicated in part D of the introduction, classification changes utilizing the MSM for urban and rural single-phase primary lines (laterals) and line transformers were recommended by the Elenchus Cost of Service Study in 2023 and implemented within this Cost of Service Study.

All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as a customer-related costs.

- **Customer:**
Customer costs are classified 100% as customer-related.

The results of the functionalization and classification (or functional classification) of rate base, expense, return on rate base, and revenue requirement are summarized in **Schedules 2.00 through to 2.36**.

STEP 4: ALLOCATION

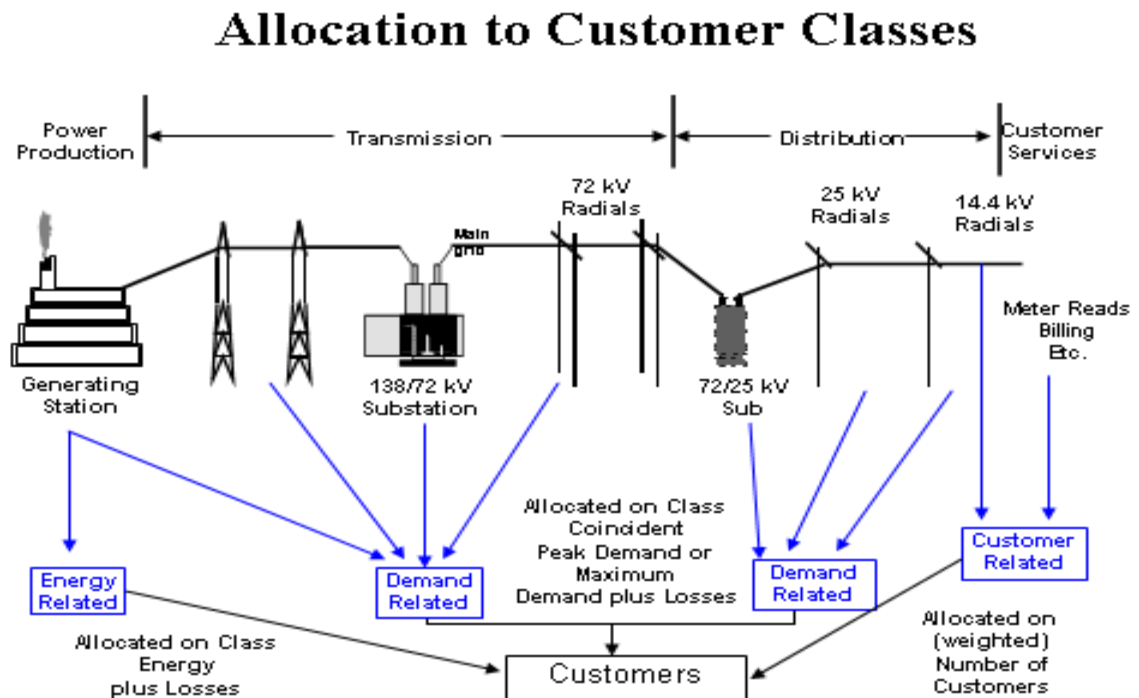
Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated:

- Residential
- Farms
- Commercial
- Power
- Oilfields
- Reseller

Figure 3 presents a schematic of the allocation process. The methodologies chosen by SaskPower for allocation are summarized in **Schedule 3.0**. The core data used in the development of allocation factors can be found in **Schedule 4.0**.

Figure 3: Allocation Schematic



An explanation of the allocation process by function is as follows:

- **Generation:**

The energy-related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand-related rate base and expenses are allocated by the Two Coincident Peak (2CP) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May, and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

- **Transmission:**

All transmission functions are classified as demand and are allocated using the 2CP method as aforementioned.

- **Distribution:**

The demand functions within distribution use a combination of the 2CP method and the Maximum Diversified Class Demands (MDD) method. The MDD method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demand of a rate class, regardless of when it occurs, during a specified period, to the sum of all the class peaks, similarly determined. Only the transformers' function uses the MDD methodology. All other functions use the 2CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight-related rate base and expenses are allocated directly to streetlights.

- **Customer Services:**

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

- **Customer Contributions:**

These contributions are allocated back directly to the customer classes which made the contribution.

- **Load Data:**

Customer load data is obtained for each class from the best available sources. Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The results for the customer types in each of these classes are then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.

Power class loads were analyzed based on hourly meter readings from actual customers' interval metered sites.

- **Loss Study:**

The purpose of a loss study is to properly quantify and assign the electrical energy and demand losses in the various segments of the system to the appropriate customer class. The starting point is the total energy loss in GWh, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

- **Allocators:**

The allocation factors are summarized in **Schedules 5.0 to 5.3**. The functionalization and classification of the revenue requirement is summarized in **Tables 1 and 2** (Summary of Results section), and the details are in **Schedules 6.0 to 6.3**.

STEP 5: COMPARE

The allocated rate base, allocated expenses, and class revenue are the foundation for calculating the revenue-to-revenue requirement (R/RR) ratio by class. A R/RR measure of 1.00 indicates that the revenues received from a customer class exactly matches the costs of providing it electrical service; or, to put it simply, a customer is paying the amount it costs SaskPower to provide them with service. An R/RR below 1.00 indicates that a customer class is paying less than the cost to serve while an R/RR above 1.00 indicates that a customer class is paying more than the cost to serve. On a system-wide basis, the ratio must equal 1.00.

In response to comments of cross-subsidization between SaskPower's customer classes, external consultants have advised SaskPower that R/RR ratios close to 1.00 are deemed to be reasonable. Cost allocation studies of shared assets utilized by various customer groups represents the best and most current information available but is subject to

fluctuations and uncertainty from year to year. A range of acceptable R/RR ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that a customer is paying their fair share of costs. As a result, a R/RR ratio that is slightly above or below 1.00 does not demonstrate that one customer class subsidizes or receives a subsidy from other customer classes if it falls within the acceptable range. In conclusion, if the R/RR ratios are within the acceptable range, the results are deemed to be reasonable and there is no refutable evidence of cross-subsidization.

R/RR ratios are determined by comparing the revenue collected from each class to the revenue required to serve the customer class. The revenue requirement for each customer class is calculated as the allocated rate base multiplied by the system return on rate base plus allocated expenses. Please refer to **Table 3** in the Summary of Results section for an R/RR ratio breakdown by customer class.

It is important to note that R/RR ratios are not static. Each year SaskPower rebuilds the cost of service model using the latest annual financial information and customer revenue and load data. As such, cost of service results will vary from year to year for several reasons, including:

- 1) Class Revenue Changes
- 2) Class Revenue Requirement Changes, due to:
 - Non-uniform escalation of generation, transmission, distribution & customer service costs (e.g., capital expenditures, fuel & purchased power, OM&A, and depreciation expense)
 - Changes to cost of service methodology
 - Changes to class demand (e.g., customer load factors) at system peak, due to:
 - Economic conditions
 - Mechanical failures
 - Unforeseen shutdowns
 - Operational changes
 - Variations in weather patterns

R/RR ratios in Base (actual) years are dependent on the actual annual revenue and the calculated revenue requirement derived from the Cost of Service Study which may reflect any, or all, of the above conditions.

In Test (forecast) years, SaskPower attempts to set the R/RR ratios between 0.98 to 1.02 using assumptions based on a “most likely” scenario, to stabilize rate designs and protect all customers from outlying or anomalous conditions that may occur. Maintaining this range is still the long-term goal, however due to the transition to a Conventional Rate

Design and the number of years since SaskPower's last rate rebalancing rate application, to avoid rate shock to certain rate classes, more discretion in the ratios had to be taken in this application.

STEP 6: DEVELOP "IDEAL" RATES

Each of SaskPower's customer classes is made up of one or more rate codes. A rate code outlines the specific price paid by a group of customers with similar characteristics. Separate rate codes may be required for size, the voltage level the customer is supplied at, or the type of load served (e.g., streetlights). SaskPower currently has 49 published rate codes.

As discussed above, one of the primary objectives of rate design is fairness and equity. To satisfy this objective, SaskPower designs rates to recover the appropriate amount of revenue from each rate code within a class. Rates are also designed to collect the appropriate revenue for an average-sized customer from their rate code within each class. Essentially this means if a class has a R/RR ratio of 1.01, then the rate will be designed such that the overall rate code and the average sized customer belonging to that rate code provides the same R/RR of 1.01.

Customer size is measured as the maximum customer demand in kW. Customer annual load factor is defined as:

Load factor = annual energy / (maximum demand * 8760 hours).

A high load factor customer has a steady load which does not vary much from hour to hour. Oilfield and Power customers typically have high load factors. A low load factor customer has high peak loads relative to the amount of energy consumed. Residential customers typically have low load factors.

The cost of service model provides the energy, demand, and customer-related revenue requirement for each class of customers (see **Table 2**), as well as for each rate code within a class. The energy, demand, and customer revenue requirement by rate code provides the basis for rate design.

Energy (Only) Metered Customers

All Residential, small Farm, and small Commercial customers have a simple energy meter. These meters cost much less than the demand & energy meter used for larger customers. The rate for energy metered customers includes an energy charge and a basic monthly charge. The combination of energy charge and basic monthly charge will collect the appropriate revenue from customers regardless of size. The energy charge and basic

monthly charge will not, however, collect the appropriate revenue for customers of all load factors. It will collect the appropriate revenue for customers at the average load factor for the rate code.

The energy charge is calculated as the energy plus demand revenue requirements divided by the rate code energy consumption. The basic monthly charge is calculated as the customer revenue requirement divided by the number of customer accounts in the rate code divided by 12 months.

Demand & Energy Metered Customers

Commercial and Farm customers over 50 kVA demand and all Power customers have a meter which measures both energy consumed in kWh and maximum monthly demand in kVA. The rates for demand & energy metered customers have separate charges for energy, demand, and the basic monthly charge. The combination of energy, demand and basic monthly charge is intended to collect the appropriate revenue for each customer regardless of size at the average load factor of the class.

SaskPower rates for demand & energy metered customers are designed using the cost of service model. Rates are designed by first determining the revenue requirement for a wide range of customer sizes and load factors. Then the rate is designed such that the appropriate revenue is collected for each combination of customer size at the average load factor of the class.

Once the energy only and the demand & energy rates are designed for all rate codes, they are tested in SaskPower's revenue model. This is done to ensure SaskPower collects the appropriate revenue overall (meets revenue requirements) and from each customer class (fairness and equity). A check is also made to ensure that no one customer receives more than the maximum allowable rate increase of 15%. The adjusted rates are finalized, approved by the Saskatchewan Rate Review Panel and Cabinet, and then published for each individual rate code.

IV. SUPPORTING SCHEDULES

Schedule 1.0: Summary of the Functionalization of Financial Account Details

Summary of the Functionalization of Financial Account Details 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Rate Base and Expense Categories	SaskPower Total	Functional Breakdown						Customer Service	
		Generation		Transmission		Distribution			
Rate Base									
Plant in Service (Schedule 1.1)	23,451.5	12,031.8	51.3%	4,350.0	18.5%	6,842.9	29.2%	226.9	1.0%
Accumulated Depreciation (Schedule 1.2)	(10,621.7)	(6,361.8)	59.9%	(1,447.1)	13.6%	(2,735.9)	25.8%	(76.9)	0.7%
Allowance For Working Capital	137.5	81.2	59.1%	18.1	13.1%	26.4	19.2%	11.8	8.6%
Inventories (Schedule 1.3)	454.5	202.2	44.5%	99.4	21.9%	153.0	33.7%	(0.1)	0.0%
Other Assets (Schedule 1.3)	88.2	68.5	77.7%	6.2	7.0%	9.1	10.3%	4.4	5.0%
Total Rate Base	13,510.0	6,022.0	44.6%	3,026.6	22.4%	4,295.5	31.8%	166.0	1.2%
Revenue Requirement									
Fuel Expense SaskPower Units	640.3	640.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchased Power & Import	308.1	308.1	100.0%	-	0.0%	-	0.0%	-	0.0%
Export & Net Electricity Trading Revenue (Credit)	(64.7)	(64.7)	100.0%	-	0.0%	-	0.0%	-	0.0%
Operating, Maintenance & Administration (Schedule 1.4)	986.6	578.9	58.7%	127.5	12.9%	187.0	19.0%	93.2	9.4%
Depreciation & Depletion (Schedule 1.5)	765.5	417.4	54.5%	114.5	15.0%	223.1	29.1%	10.5	1.4%
Corporate Capital Tax	75.6	33.4	44.2%	17.1	22.6%	24.2	32.0%	0.9	1.2%
Grants in Lieu of Taxes	36.6	36.6	100.0%	-	0.0%	-	0.0%	-	0.0%
Miscellaneous Tax	1.0	1.0	100.0%	-	0.0%	-	0.0%	-	0.0%
Other Income (Credit) (Schedule 1.6)	(179.4)	(32.8)	18.3%	(67.3)	37.5%	(68.5)	38.2%	(10.8)	6.0%
Return on Rate Base @ 4.72%	637.2	284.0	44.6%	142.8	22.4%	202.6	31.8%	7.8	1.2%
Total Revenue Requirement	3,206.8	2,202.3	68.7%	334.6	10.4%	568.3	17.7%	101.6	3.2%

Schedule 1.1: Functionalization of Financial Account Details – Plant in Service

Functionalization of Financial Account Details PLANT IN SERVICE 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Functional Breakdown					
		Generation	Transmission	Distribution	Customer Service		
Generation Assets							
Power Production	10,062.8	100.0%	-	0.0%	-	0.0%	0.0%
Power Production - PPA	1,218.4	100.0%	-	0.0%	-	0.0%	0.0%
Coal Reserves	77.8	100.0%	-	0.0%	-	0.0%	0.0%
Shand Greenhouse	6.0	100.0%	-	0.0%	-	0.0%	0.0%
Total Generation Assets	11,365.0	100.0%	-	0.0%	-	0.0%	0.0%
Transmission Assets							
Transmission Assets	3,973.2	8.1	3,925.2	98.8%	39.9	1.0%	0.0%
Total Transmission Assets	3,973.2	8.1	3,925.2	98.8%	39.9	1.0%	0.0%
Distribution Assets							
Distribution Assets	6,153.7	-	-	0.0%	6,153.7	100.0%	0.0%
Meters	155.1	-	-	0.0%	155.1	100.0%	0.0%
Instrument Transformers	26.5	-	-	0.0%	26.5	100.0%	0.0%
Total Distribution Assets	6,335.4	-	-	0.0%	6,335.4	100.0%	0.0%
General Plant Assets							
Unused Land	2.3	1.4	0.3	12.9%	0.4	19.0%	9.4%
Right of Use Land	11.2	6.6	1.4	12.9%	2.1	19.0%	9.4%
Buildings	786.0	281.7	154.4	19.6%	206.1	26.2%	18.3%
Right of Use Buildings	8.6	2.9	1.8	20.4%	2.3	27.2%	18.8%
Office Furniture & Equipment	68.6	24.6	13.5	19.6%	18.0	26.2%	18.3%
Vehicles & Equipment	285.4	44.5	94.8	33.2%	125.0	43.8%	7.4%
Computer Development & Equipment	443.9	244.3	68.3	15.4%	88.2	19.9%	9.7%
Communication, Protection & Control	144.8	45.0	81.1	56.0%	16.5	11.4%	1.6%
Tools & Equipment	27.0	7.7	9.2	34.0%	9.0	33.2%	4.1%
Total General Plant Assets	1,777.9	658.6	424.8	23.9%	467.6	26.3%	12.8%
Total Plant in Service	23,451.5	12,031.8	4,350.0	18.5%	6,842.9	29.2%	1.0%

Schedule 1.2: Functionalization of Financial Account Details – Accumulated Depreciation

Functionalization of Financial Account Details ACCUMULATED DEPRECIATION 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Functional Breakdown					
		Generation	Transmission	Distribution	Customer Service		
Generation Assets							
Power Production	(5,213.0)	(5,213.0)	-	-	0.0%	-	0.0%
Power Production - PPA	(768.8)	(768.8)	-	-	0.0%	-	0.0%
Coal Reserves	(55.7)	(55.7)	-	-	0.0%	-	0.0%
Shand Greenhouse	(4.6)	(4.6)	-	-	0.0%	-	0.0%
Total Generation Assets	(6,042.1)	(6,042.1)	-	-	0.0%	-	0.0%
Transmission Assets							
Transmission Assets	(1,259.1)	(1.9)	(1,236.1)	(21.0)	1.7%	-	0.0%
Total Transmission Assets	(1,259.1)	(1.9)	(1,236.1)	(21.0)	1.7%	-	0.0%
Distribution Assets							
Distribution Assets	(2,412.9)	-	-	(2,412.9)	100.0%	-	0.0%
Meters	(77.3)	-	-	(77.3)	100.0%	-	0.0%
Instrument Transformers	(17.8)	-	-	(17.8)	100.0%	-	0.0%
Total Distribution Assets	(2,508.0)	-	-	(2,508.0)	100.0%	-	0.0%
General Plant Assets							
Unused Land	-	-	-	-	0.0%	-	0.0%
Right of Use Land	(5.4)	(3.2)	(0.7)	(1.0)	12.9%	(0.5)	9.4%
Buildings	(112.0)	(44.9)	(20.6)	(27.5)	18.4%	(18.9)	16.9%
Right of Use Buildings	(7.3)	(2.4)	(1.5)	(2.0)	20.4%	(1.4)	18.8%
Office Furniture & Equipment	(41.9)	(16.8)	(7.7)	(10.3)	18.4%	(7.1)	16.9%
Vehicles & Equipment	(169.1)	(24.4)	(56.9)	(75.1)	33.7%	(12.7)	7.5%
Computer Development & Equipment	(345.7)	(185.3)	(55.2)	(71.5)	16.0%	(33.7)	9.8%
Communication, Protection & Control	(109.7)	(34.6)	(60.3)	(13.0)	55.0%	(1.8)	1.6%
Tools & Equipment	(21.5)	(6.0)	(8.1)	(6.6)	37.7%	(0.8)	3.8%
Total General Plant Assets	(812.5)	(317.7)	(211.0)	(206.9)	26.0%	(76.9)	9.5%
Total Accumulated Depreciation	(10,621.7)	(6,361.8)	(1,447.1)	(2,735.9)	25.8%	(76.9)	0.7%

Schedule 1.3: Functionalization of Financial Account Details – Inventories/Other Assets

Functionalization of Financial Account Details INVENTORIES 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)				

	SaskPower Total	Functional Breakdown			
		Generation	Transmission	Distribution	Customer Service
Inventories					
Power Production - Repair Stores	145.6	100.0%	-	0.0%	0.0%
Power Production - Fuel	57.4	100.0%	-	0.0%	0.0%
Transmission & Distribution	252.9	0.0%	99.6	153.3	0.0%
Miscellaneous (Computers, Power Shop)	(1.4)	58.7%	(0.2)	(0.3)	60.6%
Total Inventories	454.5	202.2	99.4	153.0	(0.1)
		44.5%	21.9%	33.7%	0.0%

Functionalization of Financial Account Details OTHER ASSETS 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)				

	SaskPower Total	Functional Breakdown			
		Generation	Transmission	Distribution	Customer Service
Other Assets					
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	100.0%	-	0.0%	0.0%
Intangible Assets	-	0.0%	-	0.0%	0.0%
Prepaid Expenses - Insurance	5.8	90.0%	0.2	0.3	0.0%
Miscellaneous Prepaid Expenses	46.2	58.7%	6.0	8.8	19.0%
Total Generation Expenses	88.2	68.5	6.2	9.1	4.4
		77.7%	7.0%	10.3%	5.0%

Schedule 1.4: Functionalization of Financial Account Details – OM&A Expense

Functionalization of Financial Account Details OM&A EXPENSES 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Expense Categories	SaskPower Total	Functional Breakdown							
		Generation		Transmission		Distribution		Customer Service	
Generation Expenses									
Power Plant Operation	302.3	302.3	100.0%	-	0.0%	-	0.0%	-	0.0%
Power Production Overhead	40.8	40.8	100.0%	-	0.0%	-	0.0%	-	0.0%
Purchase Power Agreements (PPA)	18.5	18.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Total Generation Expenses	361.5	361.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Transmission & Distribution Expenses									
Planning Support	25.1	13.6	54.3%	11.1	44.2%	0.1	0.4%	0.3	1.1%
Transmission Including 230/138 & 72 kV Radials	69.8	-	0.0%	69.8	100.0%	-	0.0%	-	0.0%
Distribution	124.4	-	0.0%	-	0.0%	124.4	100.0%	-	0.0%
Customer Services	9.1	-	0.0%	-	0.0%	-	0.0%	9.1	100.0%
Metering Services	5.8	-	0.0%	-	0.0%	-	0.0%	5.8	100.0%
Total Transmission & Distribution Expenses	234.1	13.6	5.8%	80.9	34.5%	124.5	53.2%	15.1	6.5%
Customer Services Expenses									
Meter Reading	12.9	-	0.0%	-	0.0%	-	0.0%	12.9	100.0%
Billing Services	3.5	-	0.0%	-	0.0%	-	0.0%	3.5	100.0%
Collections/Special Collections	1.7	-	0.0%	-	0.0%	-	0.0%	1.7	100.0%
Bad Debt Expense	9.0	-	0.0%	-	0.0%	-	0.0%	9.0	100.0%
Marketing & Sales	2.8	-	0.0%	-	0.0%	-	0.0%	2.8	100.0%
Demand Side Management	24.4	24.4	100.0%	-	0.0%	-	0.0%	-	0.0%
Customer Service	23.3	-	0.0%	-	0.0%	-	0.0%	23.3	100.0%
Total Customer Services Expenses	77.6	24.4	31.4%	-	0.0%	-	0.0%	53.2	68.6%
Support Group Expenses									
President / Board	2.6	1.5	58.7%	0.3	12.9%	0.5	19.0%	0.2	9.4%
Corporate & Financial Services (C&FS)	11.8	5.5	46.5%	2.2	18.4%	2.9	24.6%	1.3	10.6%
C&FS - Insurance Premiums & Insurable Losses	20.1	18.1	90.0%	0.8	4.0%	1.1	5.3%	0.1	0.6%
Asset Management, Planning, & Sustainability	29.5	15.4	52.3%	5.3	18.0%	7.1	24.1%	1.6	5.5%
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	0.0%	-	0.0%	-	0.0%
SMR Consortium	25.0	25.0	100.0%	-	0.0%	-	0.0%	-	0.0%
General Council / Land	5.9	3.5	58.7%	0.8	12.9%	1.1	19.0%	0.6	9.4%
Safety	8.0	4.1	51.5%	1.3	16.8%	1.9	23.2%	0.7	8.5%
Corporate Information & Technology	117.5	57.8	49.1%	20.4	17.3%	27.0	23.0%	12.4	10.5%
Human Resources	38.0	15.8	41.5%	7.9	20.8%	10.7	28.3%	3.6	9.4%
Commercial & Industrial Operations	13.5	13.5	100.0%	-	0.0%	-	0.0%	-	0.0%
Procurement & Supply Chain	41.3	19.2	46.5%	7.6	18.4%	10.1	24.6%	4.4	10.6%
Total Support Group Expenses	313.3	179.4	57.2%	46.6	14.9%	62.5	19.9%	24.8	7.9%
Total OM&A Expenses	986.6	578.9	58.7%	127.5	12.9%	187.0	19.0%	93.2	9.4%

Schedule 1.5: Functionalization of Financial Account Details – Depreciation & Depletion Expense

Functionalization of Financial Account Details DEPRECIATION & DEPLETION EXPENSE 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Functional Breakdown					
		Generation	Transmission	Distribution	Customer Service		
Generation Assets							
Power Production	326.6	326.6	-	-	-	0.0%	0.0%
Purchase Power Agreements (PPA)	54.1	54.1	-	-	-	0.0%	0.0%
Coal Reserves	3.0	3.0	-	-	-	0.0%	0.0%
Shand Greenhouse	0.2	0.2	-	-	-	0.0%	0.0%
Total Generation Assets	383.9	383.9	-	-	-	0.0%	0.0%
Transmission Assets							
Transmission Assets	95.5	0.1	94.3	1.1	-	1.1%	0.0%
Total Transmission Assets	95.5	0.1	94.3	1.1	-	1.1%	0.0%
Distribution Assets							
Distribution Assets	188.0	-	-	188.0	-	100.0%	0.0%
Meters	7.7	-	-	7.7	-	100.0%	0.0%
Instrument Transformers	1.6	-	-	1.6	-	100.0%	0.0%
Total Distribution Assets	197.4	-	-	197.4	-	100.0%	0.0%
General Plant Assets							
Unused Land	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	19.0%	9.4%
Right of Use Land	0.9	0.5	0.1	0.2	0.1	19.0%	9.4%
Buildings	18.4	6.3	3.7	4.9	3.4	26.9%	18.7%
Right of Use Buildings	2.3	0.8	0.5	0.6	0.4	27.2%	18.8%
Office Furniture & Equipment	4.3	1.5	0.9	1.2	0.8	26.9%	18.7%
Vehicles & Equipment	15.8	2.0	5.4	7.1	1.3	45.1%	8.0%
Computer Development & Equipment	41.8	20.7	7.2	9.6	4.4	22.9%	10.4%
Communication, Protection & Control	2.6	0.7	1.6	0.3	0.0	10.0%	1.4%
Tools & Equipment	2.7	1.0	0.8	0.8	0.1	28.7%	3.5%
Total General Plant Assets	88.7	33.4	20.2	24.6	10.5	27.7%	11.9%
Total Depreciation Expense	765.5	417.4	114.5	223.1	10.5	29.1%	1.4%

Schedule 1.6: Functionalization of Financial Account Details – Other Income

Functionalization of Financial Account Details OTHER INCOME 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)	

Expense Categories	SaskPower Total	Functional Breakdown			
		Generation	Transmission	Distribution	Customer Service
Other Income					
Customer Services Payment Charges	(8.3)	-	-	-	(8.3)
Meter Reading	(2.2)	-	-	-	(2.2)
Transmission	(4.0)	(0.6)	(3.4)	-	-
Distribution	(7.7)	-	-	(7.7)	-
Miscellaneous Other Income	(2.8)	(1.6)	(0.4)	(0.5)	(0.3)
Customer Contribution Revenue	(123.9)	-	(63.6)	(60.3)	-
Green Power Premium	(0.0)	(0.0)	-	-	-
Flyash Sales	(11.1)	(11.1)	-	-	-
CO2 Sales & Penalties	(18.6)	(18.6)	-	-	-
Renewable Energy Credits	(0.8)	(0.8)	-	-	-
Total Other Income	(179.4)	(32.8)	(67.3)	(68.5)	(10.8)
		18.3%	37.5%	38.2%	6.0%

Schedule 2.00: Functional Classification of Financial Account Details – Generation

Functionalization and Classification of Financial Account Details																	
GENERATION Related Costs																	
2027 Fiscal Test Embedded Cost of Service Study																	
(\$ Millions)																	
Rate Base and Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Basis of Classification	Load		Losses		Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve	Reactive Supply		Grants in Lieu of Taxes
					Demand	Energy	Demand	Energy			Demand	Energy			Demand	Energy	
Rate Base																	
Plant in Service (Schedule 2.01)	23,451.5	12,031.8	51.3%	Functional Class of PIS	1,988.7	7,848.7	199.7	532.6	34.0	87.7	264.2	396.3		523.4	206.4		-
Accumulated Depreciation (Schedule 2.02)	(10,621.7)	(6,361.7)	59.9%	Functional Class of Accum. Dep'n	(1,153.3)	(4,141.3)	(120.0)	(281.6)	(25.2)	(41.9)	(113.3)	(170.0)		(224.5)	(90.6)		-
Allowance for Working Capital	137.5	81.2	59.1%	12.50% of OMA& and Taxes	34.6	28.7	3.4	1.8	1.6	0.5	1.1	1.7		2.2	1.1		4.6
Inventories (Schedule 2.03)	484.5	202.2	44.5%	Functional Class of Inventories	74.0	100.7	7.8	6.9	(0.0)	0.6	2.2	3.4		4.4	2.2		-
Other Assets (Schedule 2.03)	88.2	68.5	77.7%	Functional Classification of Other Assets	15.4	45.3	1.5	3.0	0.0	0.2	0.5	0.7		0.9	0.4		-
Total Rate Base	13,510.0	6,022.0	44.6%		908.5	3,882.1	92.4	262.7	11.1	47.0	154.7	232.0		306.4	115.5		4.6
Revenue Requirement																	
Fuel Expense SaskPower Units	640.3	640.3	100.0%	Functional Class of Fuel Exp.	-	599.3	-	40.9	-	-	-	-		-	0.1		-
Purchased Power & Import	308.1	308.1	100.0%	Functional Class of PP, Import & NP Fee	80.7	204.9	8.5	14.0	-	-	-	-		-	0.0		-
Export & Net Electricity Trading Revenue (Credit)	(64.7)	(64.7)	100.0%	Functional Class of Exports	-	(60.6)	-	(4.1)	-	-	-	-		-	(0.0)		-
Operating, Maintenance & Administration (Schedule 2.04)	986.6	578.9	58.7%	Functional Class of OMA&A	271.9	207.3	26.9	13.0	13.1	3.4	7.9	11.9		15.7	7.8		-
Depreciation & Depletion (Schedule 2.05)	765.5	417.4	54.5%	Functional Class of Dep'n & Depletion	73.5	264.7	7.5	17.9	0.3	2.9	9.5	14.3		18.9	7.3		-
Corporate Capital Tax	75.6	33.4	44.2%	Functional Class of Corp. Capital Tax	4.6	21.8	0.5	1.5	0.1	0.3	0.9	1.3		1.8	0.7		-
Grants in Lieu of Taxes	36.6	36.6	100.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-		-	-		36.6
Miscellaneous Tax	1.0	1.0	100.0%	Functional Class of Misc. Tax	0.5	0.3	0.1	0.0	-	0.0	0.0	0.0		0.0	0.0		0.0
Other Income (Credit) (Schedule 2.06)	(179.4)	(28.0)	18.3%	Functional Class of Other Income	(0.8)	(29.2)	(0.1)	(2.0)	(0.6)	(0.1)	(0.0)	(0.0)		(0.0)	(0.0)		0.2
Return on Rate Base @ 4.72%	637.2	284.0	44.6%	Rate Base	42.9	383.1	4.4	12.4	0.5	18.1	7.3	10.9		14.5	5.6		0.2
Total Revenue Requirement	3,206.8	2,202.3	68.7%		473.5	1,911.8	47.7	93.6	13.7	8.7	25.7	38.5		50.8	21.5		36.8

Schedule 2.01: Functional Classification of Financial Account Details – Generation Plant in Service

Functionalization and Classification of Financial Account Details GENERATION PLANT IN SERVICE 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)															
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses Demand	Losses Energy	Scheduling & Dispatch Demand	Regulation & Frequency Response Demand	Spinning Reserve Demand	Supplementary Reserve		Planning Reserve Demand	Reactive Supply Demand	Grants in Lieu of Taxes Energy
				Demand	Energy						Demand	Energy			
Generation Assets															
Power Production	10,062.8	10,062.8	100.0%	1,129.3	7,065.0	118.7	481.8	-	64.8	228.9	343.3	453.4	177.5	-	-
Power Production - PPA	1,218.4	1,218.4	100.0%	511.2	468.1	53.7	31.9	-	7.9	27.7	41.6	54.9	21.4	-	-
Coal Reserves	77.8	77.8	100.0%	-	-	-	-	-	-	-	-	-	-	0.0	-
Shand Greenhouse	6.0	6.0	100.0%	0.8	4.8	0.1	0.3	-	-	-	-	-	-	-	-
Total Generation Assets	11,365.0	11,365.0	100.0%	1,641.3	7,610.8	172.5	519.0	-	72.7	256.6	384.9	508.3	198.9	-	-
Transmission Assets															
Transmission Assets	3,973.2	8.1	0.2%	7.4	-	0.8	-	-	-	-	-	-	-	-	-
Total Transmission Assets	3,973.2	8.1	0.2%	7.4	-	0.8	-	-	-	-	-	-	-	-	-
Distribution Assets															
Distribution Assets	6,153.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Meters	155.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Instrument Transformers	26.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	6,335.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant Assets															
General Plant Assets	2.3	1.4	58.7%	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Unused Land	11.2	6.6	58.7%	3.1	2.4	0.3	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	-
Right of Use Land	786.0	281.7	35.8%	122.8	123.6	10.0	6.6	1.8	1.0	2.9	4.4	5.8	2.9	2.9	-
Buildings	8.6	2.9	33.5%	1.2	1.3	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	-
Right of Use Buildings	68.6	24.6	35.8%	10.7	10.8	0.9	0.6	0.2	0.1	0.3	0.4	0.5	0.2	0.2	-
Office Furniture & Equipment	285.4	44.5	15.6%	22.6	15.0	2.2	0.9	0.0	0.2	0.6	1.0	1.3	0.6	0.6	-
Vehicles & Equipment	443.9	244.3	55.0%	125.1	81.8	12.4	5.1	(0.6)	1.1	3.5	5.3	7.0	3.5	3.5	-
Computer Development & Equipment	144.8	45.0	31.1%	-	-	-	-	32.5	12.5	-	-	-	-	-	-
Communication, Protection & Control	27.0	7.7	28.6%	4.0	2.5	0.4	0.2	-	0.0	0.1	0.2	0.2	0.1	0.1	-
Total General Plant Assets	1,777.9	658.6	37.0%	290.1	237.9	26.4	13.6	34.0	15.0	7.6	11.4	15.1	7.5	7.5	-
Total Plant in Service	23,451.5	12,031.8	51.3%	1,938.8	7,848.7	199.7	532.6	34.0	87.7	264.2	396.3	523.4	206.4	206.4	-

Schedule 2.02: Functional Classification of Financial Account Details – Generation Accumulated Depreciation

Functionalization and Classification of Financial Account Details																					
GENERATION ACCUMULATED DEPRECIATION																					
2027 Fiscal Test Embedded Cost of Service Study																					
(\$ Millions)																					
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Losses		Scheduling & Dispatch		Regulation & Frequency Response		Spinning Reserve		Supplementary Reserve		Planning Reserve		Grants in Lieu of Taxes	
				Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy
Generation Assets																					
Power Production	(5,213.0)	(5,213.0)	100.0%	(700.4)	(3,659.4)	(73.6)	(249.6)	(22.2)	(3.6)	(27.0)	(95.4)	(143.1)	(21.1)	(189.0)	(75.7)	(11.1)	(27.9)	(75.7)	(11.1)	-	
Power Production - PPA	(768.8)	(768.8)	100.0%	(310.3)	(325.6)	(32.6)	(22.2)	(3.6)	(3.6)	(4.0)	(14.1)	(2.1)	-	(27.9)	(11.1)	(0.0)	(27.9)	(11.1)	(0.0)	-	
Coal Reserves	(55.7)	(55.7)	100.0%	-	(52.1)	(0.1)	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	
Shard Greenhouse	(4.6)	(4.6)	100.0%	(0.7)	(3.6)	(0.1)	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Generation Assets	(6,042.1)	(6,042.1)	100.0%	(1,011.3)	(4,040.7)	(106.3)	(275.6)	(0.2)	(7.5)	(31.0)	(109.5)	(164.2)	(21.6)	(216.8)	(86.8)	(1.1)	(216.8)	(86.8)	(1.1)	-	
Transmission Assets																					
Transmission Assets	(1,259.1)	(1.9)	0.2%	(1.8)	-	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Transmission Assets	(1,259.1)	(1.9)	0.2%	(1.8)	-	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution Assets																					
Distribution Assets	(2,412.9)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Meters	(77.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Instrument Transformers	(17.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Distribution Assets	(2,508.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
General Plant Assets																					
General Plant Assets	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Right of Use Land	(5.4)	(3.2)	58.7%	(1.5)	(1.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	-	
Buildings	(112.0)	(44.9)	40.1%	(20.2)	(18.8)	(1.7)	(1.0)	(1.0)	(1.0)	(0.2)	(0.2)	(0.8)	(0.8)	(1.0)	(0.5)	(0.8)	(1.0)	(0.5)	(0.5)	-	
Right of Use Buildings	(7.3)	(2.4)	33.3%	(1.1)	(1.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	
Office Furniture & Equipment	(41.9)	(16.8)	40.1%	(7.6)	(7.0)	(0.7)	(0.4)	(0.4)	(0.4)	(0.1)	(0.1)	(0.3)	(0.3)	(0.4)	(0.2)	(0.3)	(0.4)	(0.2)	(0.2)	-	
Vehicles & Equipment	(169.1)	(24.4)	14.4%	(12.4)	(8.2)	(1.2)	(0.5)	(0.5)	(0.5)	(0.0)	(0.1)	(0.5)	(0.5)	(0.7)	(0.3)	(0.7)	(0.3)	(0.7)	(0.3)	-	
Computer Development & Equipment	(345.7)	(185.3)	53.6%	(94.5)	(62.4)	(9.3)	(3.9)	(3.9)	(3.9)	0.2	(6.9)	(2.7)	(4.0)	(5.3)	(2.6)	(4.0)	(5.3)	(2.6)	(2.6)	-	
Communication, Protection & Control	(109.7)	(34.6)	31.6%	-	-	-	-	-	-	(25.0)	(9.6)	-	-	-	-	-	-	-	-	-	
Tools & Equipment	(21.5)	(6.0)	28.0%	(3.1)	(2.0)	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	-	
Total General Plant Assets	(812.5)	(317.7)	39.1%	(140.2)	(100.6)	(13.5)	(6.1)	(6.1)	(6.1)	(25.2)	(10.9)	(3.9)	(5.8)	(7.7)	(3.8)	(3.8)	(7.7)	(3.8)	(3.8)	-	
Total Accumulated Depreciation	(10,621.7)	(6,361.8)	59.9%	(1,153.3)	(4,141.3)	(120.0)	(281.6)	(0.2)	(7.5)	(41.9)	(113.3)	(170.0)	(17.0)	(224.5)	(90.6)	(1.1)	(224.5)	(90.6)	(1.1)	-	

Schedule 2.03: Functional Classification of Financial Account Details – Generation Inventories/Other Assets

Functionalization and Classification of Financial Account Details																	
GENERATION INVENTORIES																	
2027 Fiscal Test Embedded Cost of Service Study																	
(\$ Millions)																	
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Losses Energy	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in Lieu of Taxes
				Demand	Energy	Demand	Demand		Demand	Demand		Demand	Demand				
Inventories																	
Power Production - Repair Stores	145.6	145.6	100.0%	74.4	47.3	7.8		3.2	-	-	0.6	2.3		3.4	4.5	2.2	-
Power Production - Fuel	57.4	57.4	100.0%	-	53.7	-		3.7	-	-	-	-		-	-	0.0	-
Transmission & Distribution	252.9	-	0.0%	-	-	(0.0)		(0.0)	-	-	(0.0)	-		-	-	-	-
Miscellaneous (Computers, Power Shop)	(1.4)	(0.8)	58.7%	(0.4)	(0.3)	(0.0)		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)	-
Total Inventories	454.5	202.2	44.5%	74.0	100.7	7.8		6.9	(0.0)	(0.0)	0.6	2.2		3.4	4.4	2.2	-

Functionalization and Classification of Financial Account Details GENERATION OTHER ASSETS 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)																	
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Losses Energy	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in lieu of Taxes
				Demand	Energy	Demand	Demand		Demand	Demand		Demand	Demand				
Other Assets																	Energy
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	36.3	100.0%	-	33.9	-	-	2.3	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	5.2	90.0%	2.6	1.7	0.3	-	0.1	-	0.0	0.1	0.1	0.1	0.1	0.2	0.1	-
Miscellaneous Prepaid Expenses	46.2	27.1	58.7%	12.7	9.7	1.3	0.6	0.6	0.6	0.2	0.2	0.4	0.6	0.6	0.7	0.4	-
Total Other Assets	88.2	68.5	77.7%	15.4	45.3	1.5	3.0	3.0	0.6	0.2	0.2	0.5	0.7	0.7	0.9	0.4	-

Schedule 2.04: Functional Classification of Financial Account Details – Generation OM&A Expenses

Functionalization and Classification of Financial Account Details													
GENERATION OM&A EXPENSES													
2027 Fiscal Test Embedded Cost of Service Study													
(\$ Millions)													
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses	Losses	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Grants in Lieu of Taxes
				Demand	Energy			Demand	Energy		Demand	Energy	
Generation Expenses													
Power Plant Operation	302.3	302.3	100.0%	154.4	98.1	16.2	0.0	-	6.7	1.3	4.7	7.0	4.6
Power Production Overhead	40.8	40.8	100.0%	20.8	13.2	2.2	-	-	0.9	0.2	0.6	0.9	0.6
Purchase Power Agreements (PPA)	18.5	18.5	100.0%	3.6	12.0	0.4	-	-	0.8	0.1	0.3	0.4	0.3
Total Generation Expenses	361.5	361.5	100.0%	178.9	123.3	18.8	0.0	-	8.4	1.6	5.6	8.4	5.5
Transmission & Distribution Expenses													
Planning Support	25.1	13.6	54.3%	0.0	0.2	0.0	0.0	12.4	0.0	1.1	-	-	-
Transmission including 230/138 & 72 kV Radials	68.8	-	0.0%	-	-	-	-	-	-	-	-	-	-
Distribution	124.4	-	0.0%	-	-	-	-	-	-	-	-	-	-
Customer Services	9.1	-	0.0%	-	-	-	-	-	-	-	-	-	-
Metering Services	5.8	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	234.1	13.6	5.8%	0.0	0.2	0.0	0.0	12.4	0.0	1.1	-	-	-
Customer Services Expenses													
Meter Reading	12.9	-	0.0%	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	1.7	-	0.0%	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	9.0	-	0.0%	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	2.8	-	0.0%	-	-	-	-	-	-	-	-	-	-
Demand Side Management	24.4	24.4	100.0%	12.2	12.2	-	-	-	-	-	-	-	-
Customer Service	23.3	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	77.6	24.4	31.4%	12.2	12.2	-	-	-	-	-	-	-	-
Support Group Expenses													
President / Board	2.6	1.5	58.7%	0.7	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate & Financial Services (C&FS)	11.8	5.5	46.5%	2.5	2.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.1
C&FS Insurance Premiums & Insurable Losses	20.1	18.1	90.0%	9.3	5.9	1.0	0.4	-	0.3	0.1	0.4	0.6	0.3
Asset Management, Planning, & Sustainability	29.5	15.4	52.3%	4.8	8.6	0.5	0.6	0.1	0.6	0.0	0.1	0.2	0.1
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-
SMK Consortium	25.0	25.0	100.0%	12.8	8.1	1.3	0.6	-	-	0.1	0.4	0.6	0.4
General Council / Land	5.9	3.5	58.7%	1.6	1.2	0.2	0.1	0.1	0.1	0.0	0.1	0.1	0.0
Safety	6.0	4.1	51.5%	2.0	1.4	0.2	0.1	0.1	0.1	0.0	0.1	0.1	0.1
Corporate Information & Technology	117.5	57.8	49.1%	28.5	20.5	2.8	1.3	0.1	0.8	0.2	0.8	1.2	0.8
Human Resources	38.0	15.8	41.5%	7.3	5.9	0.7	0.4	0.2	0.2	0.1	0.2	0.3	0.2
Commercial & Industrial Operations	13.5	13.5	100.0%	2.4	9.7	0.3	0.7	-	0.5	0.0	0.1	0.1	0.1
Procurement & Supply Chain	41.3	19.2	46.5%	8.8	7.5	0.9	0.5	-	0.7	0.1	0.2	0.4	0.2
Total Support Group Expenses	313.3	179.4	57.2%	80.8	71.6	8.1	4.6	0.7	4.6	0.7	2.3	3.5	2.3
Total OM&A Expenses	986.6	578.9	58.7%	271.9	207.3	26.9	13.0	13.1	15.7	3.4	7.9	11.9	7.8

Schedule 2.05: Functional Classification of Financial Account Details – Generation Depreciation & Depletion

Functionalization and Classification of Financial Account Details GENERATION DEPRECIATION & DEPLETION 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)														
Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load	Losses	Losses	Scheduling & Dispatch	Regulation & Frequency Response	Spinning Reserve	Supplementary Reserve	Planning Reserve	Reactive Supply	Grants in lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Demand	Demand	Demand	Demand	Demand	Demand
Generation Assets														
Power Production	326.6	326.6	100.0%	34.8	229.2	3.7	15.6	-	2.2	7.8	11.7	15.5	5.9	-
Purchase Power Agreements (PPA)	54.1	54.1	100.0%	22.9	20.2	2.4	1.4	-	0.4	1.3	1.9	2.6	1.0	-
Coal Reserves	3.0	3.0	100.0%	-	2.8	-	0.2	-	-	-	-	-	-	-
Shand Greenhouse	0.2	0.2	100.0%	0.0	0.1	0.0	0.0	-	-	-	-	-	-	-
Total Generation Assets	383.9	383.9	100.0%	57.8	252.4	6.1	17.2	-	2.6	9.1	13.7	18.1	6.9	-
Transmission Assets														
Transmission Assets	95.5	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-
Total Transmission Assets	95.5	0.1	0.1%	0.1	-	0.0	-	-	-	-	-	-	-	-
Distribution Assets														
Distribution Assets	188.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Instrument Transformers	1.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	197.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
General Plant Assets														
Unused Land	(0.0)	(0.0)	58.7%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Right of Use Land	0.9	0.5	58.7%	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Buildings	18.4	6.3	34.2%	2.7	2.8	0.2	0.1	0.0	0.0	0.1	0.1	0.1	0.1	-
Right of Use Buildings	2.3	0.8	33.5%	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Office Furniture & Equipment	4.3	1.5	34.2%	0.6	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Vehicles & Equipment	15.8	2.0	12.7%	1.0	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	-
Computer Development & Equipment	41.8	20.7	49.4%	10.2	7.3	1.0	0.4	0.0	0.1	0.3	0.4	0.6	0.3	-
Communication, Protection & Control	2.6	0.7	28.3%	-	-	-	-	0.5	0.2	-	-	-	-	-
Tools & Equipment	2.7	1.0	36.0%	0.5	0.3	0.1	0.0	-	0.0	0.0	0.0	0.0	0.0	-
Total General Plant Assets	88.7	33.4	37.6%	15.6	12.3	1.5	0.7	0.6	0.3	0.4	0.6	0.8	0.4	-
Total Depreciation & Depletion	765.5	417.4	54.5%	73.5	264.7	7.5	17.9	0.6	2.9	9.5	14.3	18.9	7.3	-

Schedule 2.06: Functional Classification of Financial Account Details – Generation Other Income

Functionalization and Classification of Financial Account Details												
GENERATION OTHER INCOME												
2027 Fiscal Test Embedded Cost of Service Study												
(\$ Millions)												
Expense Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load		Losses		Scheduling & Dispatch		Regulation & Frequency Response		Grants in Lieu of Taxes
				Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	
Other Income												
Customer Services Payment Charges	(8.3)	-	0.0%	-	-	-	-	-	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-	-	-	-	-	-
Transmission	(4.0)	(0.6)	14.2%	-	-	-	-	(0.5)	(0.0)	-	-	-
Distribution	(7.7)	-	0.0%	-	-	-	-	-	-	-	-	-
Miscellaneous Other Income	(2.8)	(1.6)	58.7%	(0.8)	(0.6)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-
Customer Contributions Revenue	(123.9)	-	0.0%	-	-	-	-	-	-	-	-	-
Green Power Premium	(0.0)	(0.0)	100.0%	-	(0.0)	-	(0.0)	-	-	-	-	-
Flyash Sales	(11.1)	(11.1)	100.0%	-	(10.4)	-	(0.7)	-	-	-	(0.0)	-
CO2 Sales & Penalties	(18.6)	(18.6)	100.0%	-	(17.4)	-	(1.2)	-	-	-	(0.0)	-
Renewable Energy Credits	(0.8)	(0.8)	100.0%	-	(0.8)	-	(0.1)	-	-	-	(0.0)	-
Total Other Income	(179.4)	(32.8)	18.3%	(0.8)	(29.2)	(0.1)	(2.0)	(0.6)	(0.1)	(0.0)	(0.0)	(0.0)

Schedule 2.10: Functional Classification of Financial Account Details – Transmission

Functionalization and Classification of Financial Account Details								
TRANSMISSION Related Costs								
2027 Fiscal Test Embedded Cost of Service Study								
(\$ Millions)								
Rate Base and Expense Categories	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Basis of Classification	Main Grid	230kV & 138kV Radials	138/72 kV Substations	72 kV Lines Radials
					Demand	Demand	Demand	Demand
Rate Base								
Plant in Service (Schedule 2.11)	23,451.5	4,350.0	18.5%	Functional Class of PIS	2,675.1	999.7	218.6	456.5
Accumulated Depreciation (Schedule 2.12)	(10,621.7)	(1,447.1)	13.6%	Functional Class of Accum. Depr'n	(865.4)	(364.1)	(85.7)	(131.9)
Allowance for Working Capital	137.5	18.1	13.1%	12.50% of OM&A and Taxes	11.0	4.0	1.4	1.7
Inventories (Schedule 2.13)	454.5	99.4	21.9%	Functional Class of Inventories	60.4	22.2	7.9	8.9
Other Assets (Schedule 2.13)	88.2	6.2	7.0%	Functional Classification of Other Assets	3.8	1.4	0.5	0.6
Total Rate Base	13,510.0	3,026.6	22.4%		1,885.0	663.2	142.7	335.7
Revenue Requirement								
Fuel Expense SaskPower Units	640.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-
Purchased Power & Import	308.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(64.7)	-	0.0%	Functional Class of Exports	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.14)	986.6	127.5	12.9%	Functional Class of OM&A	77.5	28.4	10.2	11.4
Depreciation & Depletion (Schedule 2.15)	765.5	114.5	15.0%	Functional Class of Depr'n & Depletion	69.1	28.1	5.3	12.0
Corporate Capital Tax	75.6	17.1	22.6%	Functional Class of Corp. Capital Tax	10.7	3.7	0.8	1.9
Grants in Lieu of Taxes	36.6	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	-	-	-	-
Other Income (Credit) (Schedule 2.16)	(179.4)	(67.3)	37.5%	Functional Class of Other Income	(10.4)	(54.5)	(0.3)	(2.1)
Return on Rate Base @ 4.72%	637.2	142.8	22.4%	Rate Base	88.9	31.3	6.7	15.8
Total Revenue Requirement	3,206.8	334.6	10.4%		235.7	37.0	22.7	39.1

Schedule 2.11: Functional Classification of Financial Account Details – Transmission Plant in Service

Functionalization and Classification of Financial Account Details TRANSMISSION PLANT IN SERVICE 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)											
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Generation Assets											
Power Production	10,062.8	-	0.0%	-		-		-		-	-
Power Production - PPA	1,218.4	-	0.0%	-		-		-		-	-
Coal Reserves	77.8	-	0.0%	-		-		-		-	-
Shand Greenhouse	6.0	-	0.0%	-		-		-		-	-
Total Generation Assets	11,365.0	-	0.0%	-		-		-		-	-
Transmission Assets											
Transmission Assets	3,973.2	3,925.2	98.8%	2,416.8		904.9		184.7		418.7	418.7
Total Transmission Assets	3,973.2	3,925.2	98.8%	2,416.8		904.9		184.7		418.7	418.7
Distribution Assets											
Distribution Assets	6,153.7	-	0.0%	-		-		-		-	-
Meters	155.1	-	0.0%	-		-		-		-	-
Instrument Transformers	26.5	-	0.0%	-		-		-		-	-
Total Distribution Assets	6,335.4	-	0.0%	-		-		-		-	-
General Plant Assets											
Unused Land	2.3	0.3	12.9%	0.2		0.1		0.0		0.0	0.0
Right of Use Land	11.2	1.4	12.9%	0.9		0.3		0.1		0.1	0.1
Buildings	786.0	154.4	19.6%	93.9		34.4		12.3		13.8	13.8
Right of Use Buildings	8.6	1.8	20.4%	1.1		0.4		0.1		0.1	0.2
Office Furniture & Equipment	68.6	13.5	19.6%	8.2		3.0		1.1		1.2	1.2
Vehicles & Equipment	285.4	94.8	33.2%	57.6		21.1		7.6		8.4	8.4
Computer Development & Equipment	443.9	68.3	15.4%	41.5		15.2		5.5		6.1	6.1
Communication, Protection & Control	144.8	81.1	56.0%	49.3		18.1		6.5		7.2	7.2
Tools & Equipment	27.0	9.2	34.0%	5.6		2.1		0.7		0.8	0.8
Total General Plant Assets	1,777.9	424.8	23.9%	258.3		94.8		33.9		37.8	37.8
Total Plant In Service	23,451.5	4,350.0	18.5%	2,675.1		999.7		218.6		456.5	456.5

Schedule 2.12: Functional Classification of Financial Account Details – Transmission Accumulated Depreciation

Functionalization and Classification of Financial Account Details							
TRANSMISSION ACCUMULATED DEPRECIATION							
2027 Fiscal Test Embedded Cost of Service Study							
(\$ Millions)							
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials	
				Demand		Demand	
Generation Assets							
Power Production	(5,213.0)	-	0.0%	-	-	-	-
Power Production - PPA	(768.8)	-	0.0%	-	-	-	-
Coal Reserves	(55.7)	-	0.0%	-	-	-	-
Shand Greenhouse	(4.6)	-	0.0%	-	-	-	-
Total Generation Assets	(6,042.1)	-	0.0%	-	-	-	-
Transmission Assets							
Transmission Assets	(1,259.1)	(1,236.1)	98.2%	(737.1)	(317.1)	(68.9)	(113.1)
Total Transmission Assets	(1,259.1)	(1,236.1)	98.2%	(737.1)	(317.1)	(68.9)	(113.1)
Distribution Assets							
Distribution Assets	(2,412.9)	-	0.0%	-	-	-	-
Meters	(77.3)	-	0.0%	-	-	-	-
Instrument Transformers	(17.8)	-	0.0%	-	-	-	-
Total Distribution Assets	(2,508.0)	-	0.0%	-	-	-	-
General Plant Assets							
Unused Land	-	-	0.0%	-	-	-	-
Right of Use Land	(5.4)	(0.7)	12.9%	(0.4)	(0.2)	(0.1)	(0.1)
Buildings	(112.0)	(20.6)	18.4%	(12.5)	(4.6)	(1.6)	(1.8)
Right of Use Buildings	(7.3)	(1.5)	20.4%	(0.9)	(0.3)	(0.1)	(0.1)
Office Furniture & Equipment	(41.9)	(7.7)	18.4%	(4.7)	(1.7)	(0.6)	(0.7)
Vehicles & Equipment	(169.1)	(56.9)	33.7%	(34.6)	(12.7)	(4.5)	(5.1)
Computer Development & Equipment	(345.7)	(55.2)	16.0%	(33.5)	(12.3)	(4.4)	(4.9)
Communication, Protection & Control	(109.7)	(60.3)	55.0%	(36.7)	(13.5)	(4.8)	(5.4)
Tools & Equipment	(21.5)	(8.1)	37.7%	(4.9)	(1.8)	(0.6)	(0.7)
Total General Plant Assets	(812.5)	(211.0)	26.0%	(128.3)	(47.1)	(16.8)	(18.8)
Total Accumulated Depreciation	(10,621.7)	(1,447.1)	13.6%	(865.4)	(364.1)	(85.7)	(131.9)

Schedule 2.13: Functional Classification of Financial Account Details – Transmission Inventories/Other Assets

Functionalization and Classification of Financial Account Details									
TRANSMISSION INVENTORIES									
2027 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Inventories											
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-	-	-
Power Production - Fuel	57.4	-	0.0%	-	-	-	-	-	-	-	-
Transmission & Distribution	252.9	99.6	39.4%	60.6	22.2	22.2	7.9	7.9	8.9	8.9	8.9
Miscellaneous (Computers, Power Shop)	(1.4)	(0.2)	12.9%	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Inventories	454.5	99.4	21.9%	60.4	22.2	22.2	7.9	7.9	8.9	8.9	8.9

Functionalization and Classification of Financial Account Details									
TRANSMISSION OTHER ASSETS									
2027 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									

Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid		230kV & 138kV Radials		138/72kV Substations		72kV Radials	
				Demand		Demand		Demand		Demand	
Other Assets											
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.2	4.0%	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	6.0	12.9%	3.6	1.3	1.3	0.5	0.5	0.5	0.5	0.5
Total Other Assets	88.2	6.2	7.0%	3.8	1.4	1.4	0.5	0.5	0.6	0.6	0.6

Schedule 2.14: Functional Classification of Financial Account Details – Transmission OM&A Expenses

Functionalization and Classification of Financial Account Details							
TRANSMISSION OM&A EXPENSE							
2027 Fiscal Test Embedded Cost of Service Study							
(\$ Millions)							
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
Generation Expenses				Demand	Demand	Demand	Demand
Power Plant Operation	302.3	-	0.0%	-	-	-	-
Power Production Overhead	40.8	-	0.0%	-	-	-	-
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-
Total Generation Expenses	361.5	-	0.0%	-	-	-	-
Transmission & Distribution Expenses							
Planning Support	25.1	11.1	44.2%	6.8	2.6	0.5	1.2
Transmission Including 230/138 & 72 kV Radials	69.8	69.8	100.0%	42.3	15.5	5.9	6.0
Distribution	124.4	-	0.0%	-	-	-	-
Customer Services	9.1	-	0.0%	-	-	-	-
Metering Services	5.8	-	0.0%	-	-	-	-
Total Transmission & Distribution Expenses	234.1	80.9	34.5%	49.2	18.0	6.5	7.2
Customer Services Expenses							
Meter Reading	12.9	-	0.0%	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-
Collections/Special Collections	1.7	-	0.0%	-	-	-	-
Bad Debt Expense	9.0	-	0.0%	-	-	-	-
Marketing & Sales	2.8	-	0.0%	-	-	-	-
Demand Side Management	24.4	-	0.0%	-	-	-	-
Customer Service	23.3	-	0.0%	-	-	-	-
Total Customer Services Expenses	77.6	-	0.0%	-	-	-	-
Support Group Expenses							
President / Board	2.6	0.3	12.9%	0.2	0.1	0.0	0.0
Corporate & Financial Services (C&FS)	11.8	2.2	18.4%	1.3	0.5	0.2	0.2
C&FS - Insurance Premiums & Insurable Losses	20.1	0.8	4.0%	0.5	0.2	0.1	0.1
Asset Management, Planning, & Sustainability	29.5	5.3	18.0%	3.2	1.2	0.4	0.5
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-
SMR Consortium	25.0	-	0.0%	-	-	-	-
General Council / Land	5.9	0.8	12.9%	0.5	0.2	0.1	0.1
Safety	8.0	1.3	16.8%	0.8	0.3	0.1	0.1
Corporate Information & Technology	117.5	20.4	17.3%	12.4	4.5	1.6	1.8
Human Resources	38.0	7.9	20.8%	4.8	1.8	0.6	0.7
Commercial & Industrial Operations	13.5	-	0.0%	-	-	-	-
Procurement & Supply Chain	41.3	7.6	18.4%	4.6	1.7	0.6	0.7
Total Support Group Expenses	313.3	46.6	14.9%	28.4	10.4	3.7	4.2
Total OM&A Expenses	986.6	127.5	12.9%	77.5	28.4	10.2	11.4

Schedule 2.15: Functional Classification of Financial Account Details – Transmission Depreciation & Depletion

Functionalization and Classification of Financial Account Details TRANSMISSION DEPRECIATION & DEPLETION 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)							
Asset Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
				Demand	Demand	Demand	Demand
Generation Assets							
Power Production	326.6	-	0.0%	-	-	-	-
Purchase Power Agreements (PPA)	54.1	-	0.0%	-	-	-	-
Coal Reserves	3.0	-	0.0%	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-
Total Generation Assets	383.9	-	0.0%	-	-	-	-
Transmission Assets							
Transmission Assets	95.5	94.3	98.7%	56.8	23.6	3.7	10.2
Total Transmission Assets	95.5	94.3	98.7%	56.8	23.6	3.7	10.2
Distribution Assets							
Distribution Assets	188.0	-	0.0%	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-
Instrument Transformers	1.6	-	0.0%	-	-	-	-
Total Distribution Assets	197.4	-	0.0%	-	-	-	-
General Plant Assets							
Unused Land	(0.0)	(0.0)	12.9%	(0.0)	(0.0)	(0.0)	(0.0)
Right of Use Land	0.9	0.1	12.9%	0.1	0.0	0.0	0.0
Buildings	18.4	3.7	20.2%	2.3	0.8	0.3	0.3
Right of Use Buildings	2.3	0.5	20.4%	0.3	0.1	0.0	0.0
Office Furniture & Equipment	4.3	0.9	20.2%	0.5	0.2	0.1	0.1
Vehicles & Equipment	15.8	5.4	34.2%	3.3	1.2	0.4	0.5
Computer Development & Equipment	41.8	7.2	17.3%	4.4	1.6	0.6	0.6
Communication, Protection & Control	2.6	1.6	60.4%	0.9	0.3	0.1	0.1
Tools & Equipment	2.7	0.8	31.8%	0.5	0.2	0.1	0.1
Total General Plant Assets	88.7	20.2	22.8%	12.3	4.5	1.6	1.8
Total Depreciation & Depletion	765.5	114.5	15.0%	69.1	28.1	5.3	12.0

Schedule 2.16: Functional Classification of Financial Account Details – Transmission Other Income

Functionalization and Classification of Financial Account Details							
TRANSMISSION OTHER INCOME							
2027 Fiscal Test Embedded Cost of Service Study							
(\$ Millions)							
Expense Categories	SaskPower Total	Transmission Total	Transmission as % of SaskPower Total	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
				Demand	Demand	Demand	Demand
Other Income							
Customer Services Payment Charges	(8.3)	-	0.0%	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-
Transmission	(4.0)	(3.4)	85.8%	(2.1)	(0.8)	(0.3)	(0.3)
Distribution	(7.7)	-	0.0%	-	-	-	-
Miscellaneous Other Income	(2.8)	(0.4)	12.9%	(0.2)	(0.1)	(0.0)	(0.0)
Customer Contribution Revenue	(123.9)	(63.6)	51.3%	(8.2)	(53.7)	-	(1.7)
Green Power Premium	(0.0)	-	0.0%	-	-	-	-
Flyash Sales & Wind Power	(11.1)	-	0.0%	-	-	-	-
CO2 Sales & Penalties	(18.6)	-	0.0%	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-
Total Other Income	(179.4)	(67.3)	37.5%	(10.4)	(54.5)	(0.3)	(2.1)

Schedule 2.20: Functional Classification of Financial Account Details – Distribution

Functionalization and Classification of Financial Account Details																		
DISTRIBUTION Related Costs																		
2027 Fiscal Test Embedded Cost of Service Study (\$Millions)																		
Rate Base and Expense Categories	S&P-Power Total	Distribution Total	Distribution as a % of S&P-Power Total	Basis of Classification	Area Substitutions	Distribution Needs		Urban Laterals		Rural Laterals		Transformers	Transformers	Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streightlights
						Demand	Customer	Demand	Customer	Demand	Customer							
Rate Base																		
Plant In Service (Schedule 2.21)	23,451.5	6,842.9	29.2%	Functional Class of PHS	62.58	1,894.1	208.1	485.6	897.7	535.7	288.5	1,159.2	26.5	-	181.5	-	-	-
Accumulated Depreciation (Schedule 2.22)	(12,735.9)	(10,621.7)	25.8%	Functional Class of Accum. Dep'n	(24.30)	(784.0)	(96.1)	(224.2)	(416.7)	(180.0)	(178.6)	(354.2)	(17.8)	-	(67.7)	(77.3)	-	-
Allowance for Working Capital	137.5	26.4	19.2%	12.50% of OM&A and Taxes	24.0	7.5	1.1	2.5	2.0	4.8	2.5	1.0	0.8	-	0.1	-	-	-
Inventories (Schedule 2.23)	454.5	153.0	33.7%	Functional Class of Inventories	13.9	43.6	15.3	15.3	12.3	28.8	14.9	8.0	2.6	-	6.5	-	-	-
Other Assets (Schedule 2.23)	88.2	9.1	10.3%	Functional Classification of Other Assets	0.8	2.6	0.4	0.9	0.7	1.7	0.9	0.5	-	-	8.0	-	-	-
Total Rate Base	13,510.0	4,295.5	31.8%	Functional Classification of Other Assets	39.99	1,163.8	120.1	230.2	516.2	374.0	201.4	806.7	8.7	-	123.3	-	-	-
Revenue Requirement																		
Fuel Expense S&P-Power Units	640.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchased Power & Import	308.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(647.7)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.24)	986.6	187.0	19.0%	Functional Class of OM&A	17.0	53.3	8.0	18.7	15.1	35.2	18.2	9.8	3.2	-	8.4	-	-	-
Depreciation & Depletion (Schedule 2.25)	765.5	233.1	29.1%	Functional Class of Dep'n & Depletion	20.8	54.4	6.9	16.1	12.8	29.9	10.4	10.5	35.3	1.6	7.7	-	-	-
Corporate Capital Tax	756.6	24.2	32.0%	Functional Class of Corp. Capital Tax	2.3	6.5	0.7	1.5	1.2	2.8	2.1	1.1	4.7	0.1	0.5	-	-	-
Grants in Lieu of Taxes	366.6	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Income (Credit) (Schedule 2.26)	(685.1)	(68.5)	38.2%	Functional Class of Other Income	(0.7)	(4.2)	(1.1)	(2.6)	(2.9)	(6.7)	(0.8)	(0.4)	(44.8)	-	(4.3)	-	-	-
Return on Rate Base @ 7.2%	637.2	203.6	31.8%	Rate Base	13.94	54.9	17.6	13.2	10.4	24.3	9.5	38.1	0.4	-	5.4	-	-	-
Total Revenue Requirement	3,204.8	568.3	17.7%	Rate Base	58.2	165.0	20.1	47.0	85.6	56.6	30.5	36.5	2.1	-	11.9	-	-	-

Schedule 2.21: Functional Classification of Financial Account Details – Distribution Plant in Service

Functionalization and Classification of Financial Account Details														
DISTRIBUTION PLANT IN SERVICE														
2027 Fiscal Test Embedded Cost of Service Study														
(\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Streetlights
				Demand		Demand		Demand		Demand		Demand		
Generation Assets														
Power Production - PPA	10,062.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Power Production - PPA	1,218.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	77.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Shard Greenhouse	6.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	11,365.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission Assets														
Transmission Assets	3,973.2	39.9	1.0%	39.9	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	3,973.2	39.9	1.0%	39.9	-	-	-	-	-	-	-	-	-	-
Distribution Assets														
Distribution Assets	6,153.7	6,153.7	100.0%	543.4	1,760.7	1,760.7	188.0	438.7	347.0	490.2	263.9	1,151.2	-	160.8
Meters	155.1	155.1	100.0%	-	-	-	-	-	-	-	-	-	-	155.1
Instrument Transformers	26.5	26.5	100.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	6,335.4	6,335.4	100.0%	543.4	1,760.7	1,760.7	188.0	438.7	347.0	490.2	263.9	1,151.2	26.5	160.8
General Plant Assets														
Unused Land	2.3	0.4	19.0%	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Right of Use Land	11.2	2.1	19.0%	0.2	0.6	0.1	0.2	0.2	0.4	0.2	0.1	0.1	-	0.1
Buildings	786.0	206.1	26.2%	18.7	58.8	8.9	20.7	16.6	38.8	20.1	10.8	3.5	-	9.3
Office of Use Buildings	8.6	2.3	27.2%	0.2	0.7	0.1	0.2	0.2	0.4	0.2	0.1	0.0	-	0.1
Office Furniture & Equipment	68.6	18.0	26.2%	1.6	5.1	0.8	1.8	1.5	3.4	1.8	0.9	0.3	-	0.8
Vehicles & Equipment	285.4	125.0	43.8%	11.3	35.6	5.4	12.5	10.1	23.5	12.2	6.6	2.1	-	5.6
Computer Development & Equipment	443.4	88.2	19.9%	8.0	25.2	3.8	8.8	7.1	16.6	8.6	4.6	1.5	-	4.0
Communication, Protection & Control	144.8	16.5	11.4%	1.5	4.7	0.7	1.7	1.3	3.1	1.6	0.9	0.3	-	0.7
Tools & Equipment	27.0	9.0	33.2%	0.8	2.6	0.4	0.9	0.7	1.7	0.9	0.5	0.2	-	0.4
Total General Plant Assets	1,777.9	467.6	26.3%	42.5	133.4	20.1	46.9	37.7	85.0	45.6	24.5	7.9	26.5	21.1
Total Plant in Service	23,451.5	6,842.9	29.2%	625.8	1,894.1	208.1	485.6	384.7	897.7	535.7	288.5	1,159.2	155.1	181.9

Schedule 2.22: Functional Classification of Financial Account Details – Distribution Accumulated Depreciation

Functionalization and Classification of Financial Account Details														
DISTRIBUTION ACCUMULATED DEPRECIATION														
2027 Fiscal Test Embedded Cost of Service Study														
(\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Urban Laterals		Rural Laterals		Streetlights
				Demand		Demand		Demand		Demand		Demand		
Generation Assets														
Power Production	(5,213.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Power Production - PPA	(768.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Coal Reserves	(56.7)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Stand Greenhouse	(4.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Generation Assets	(6,042.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission Assets														
Transmission Assets	(1,259.1)	(21.0)	1.7%	(21.0)	-	-	-	-	-	-	-	-	-	-
Total Transmission Assets	(1,259.1)	(21.0)	1.7%	(21.0)	-	-	-	-	-	-	-	-	-	-
Distribution Assets														
Distribution Assets	(2,412.9)	(2,412.9)	100.0%	(203.2)	(725.0)	(87.2)	(161.9)	(203.4)	(377.8)	(159.9)	(86.1)	(350.7)	(17.8)	(57.7)
Meters	(77.3)	(77.3)	100.0%	-	-	-	-	-	-	-	-	-	(17.8)	(17.3)
Instrument Transformers	(17.8)	(17.8)	100.0%	-	-	-	-	-	-	-	-	-	-	-
Total Distribution Assets	(2,508.0)	(2,508.0)	100.0%	(203.2)	(725.0)	(87.2)	(161.9)	(203.4)	(377.8)	(159.9)	(86.1)	(350.7)	(17.8)	(57.7)
General Plant Assets														
Unused Land	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Right of Use Land	(5.4)	(1.0)	19.0%	(0.3)	(0.3)	(0.0)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)
Buildings	(112.0)	(27.5)	24.5%	(2.5)	(7.8)	(1.2)	(2.2)	(2.8)	(5.2)	(2.7)	(1.4)	(0.5)	(1.2)	(1.2)
Right of Use Buildings	(7.3)	(2.0)	27.2%	(0.2)	(0.6)	(0.1)	(0.2)	(0.2)	(0.4)	(0.2)	(0.1)	(0.0)	(0.1)	(0.1)
Office Furniture & Equipment	(41.9)	(10.3)	24.5%	(0.9)	(2.9)	(0.4)	(0.8)	(1.0)	(1.9)	(1.0)	(0.5)	(0.2)	(0.5)	(0.5)
Vehicles & Equipment	(169.1)	(75.1)	44.4%	(6.8)	(21.4)	(3.2)	(6.1)	(7.5)	(14.1)	(7.3)	(3.9)	(1.3)	(3.4)	(3.4)
Computer Development & Equipment	(345.7)	(71.5)	20.7%	(6.5)	(20.4)	(3.1)	(5.8)	(7.2)	(13.4)	(7.0)	(3.7)	(1.2)	(3.2)	(3.2)
Communication, Protection & Control	(109.7)	(13.0)	11.8%	(1.2)	(3.7)	(0.6)	(1.0)	(1.3)	(2.4)	(1.3)	(0.7)	(0.2)	(0.6)	(0.6)
Tools & Equipment	(21.5)	(6.6)	30.5%	(0.6)	(1.9)	(0.3)	(0.5)	(0.7)	(1.2)	(0.6)	(0.3)	(0.1)	(0.3)	(0.3)
Total General Plant Assets	(812.5)	(206.9)	25.5%	(18.8)	(59.0)	(8.9)	(16.7)	(20.7)	(38.9)	(20.2)	(10.9)	(35.2)	(17.8)	(9.3)
Total Accumulated Depreciation	(10,621.7)	(2,735.9)	25.8%	(243.0)	(784.0)	(86.1)	(178.6)	(224.2)	(418.7)	(180.0)	(96.9)	(354.2)	(17.3)	(67.0)

Schedule 2.23: Functional Classification of Financial Account Details – Distribution Inventories/Other Assets

Functionalization and Classification of Financial Account Details														
DISTRIBUTION INVENTORIES														
2027 Fiscal Test Embedded Cost of Service Study														
(\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services
				Demand		Demand		Demand		Demand		Demand		
Inventories														
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Power Production - Fuel	57.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Transmission & Distribution	252.9	153.3	60.6%	13.9	43.7	43.7	15.4	12.4	28.8	14.9	8.0	2.6	2.6	6.9
Miscellaneous (Computers, Power Shop)	(1.4)	(0.3)	19.0%	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	(0.0)
Total Inventories	454.5	153.0	33.7%	13.9	43.6	43.6	15.3	12.3	28.8	14.9	8.0	2.6	-	6.9

Functionalization and Classification of Financial Account Details														
DISTRIBUTION OTHER ASSETS														
2027 Fiscal Test Embedded Cost of Service Study														
(\$ Millions)														
Asset Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services
				Demand		Demand		Demand		Demand		Demand		
Other Assets														
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.3	5.3%	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	8.6	19.0%	0.8	2.5	2.5	0.4	0.7	1.6	0.9	0.3	0.1	0.1	0.1
Total Other Assets	88.2	9.1	10.3%	0.8	2.6	2.6	0.3	0.7	1.7	0.9	0.3	0.2	-	0.1

Schedule 2.24: Functional Classification of Financial Account Details – Distribution OM&A Expenses

Functionalization and Classification of Financial Account Details														
DISTRIBUTION OM&A EXPENSES														
2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)														
Expense Categories	SaskPower Total	Distribution Total	Distribution % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers Demand		Streelights Customer
				Demand		Demand		Demand	Customer	Demand	Customer	Transformers Customer	Services Customer	
Generation Expenses														
Power Plant Operation	302.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Power Production Overhead	40.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Generation Expenses	361.5		0.0%											
Transmission & Distribution Expenses														
Planning Support	25.1	0.1	0.4%	0.0	0.1	-	-	-	-	-	-	-	-	-
Transmission including 230/138 & 72 kV Radials	69.8	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	124.4	124.4	100.0%	11.3	35.4	5.3	12.5	10.0	23.4	12.1	6.5	2.1	2.1	5.6
Customer Services	9.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Metering Services	5.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Transmission & Distribution Expenses	284.1	124.5	58.2%	11.3	35.5	5.3	12.5	10.0	23.4	12.1	6.5	2.1	2.1	5.6
Customer Services Expenses														
Meter Reading	12.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Billing Services	3.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Collections/Special Collections	1.7	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	9.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Marketing & Sales	2.8	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	24.4	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Customer Service	23.3	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Total Customer Services Expenses	77.6		0.0%											
Support Group Expenses														
President / Board	2.6	0.5	19.0%	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Corporate & Financial Services (C&FS)	11.8	2.9	24.6%	0.3	0.8	0.1	0.3	0.2	0.5	0.3	0.2	0.0	0.0	0.1
C&FS - Insurance Premiums & Insurable Losses	20.1	1.1	5.3%	0.1	0.3	0.0	0.1	0.1	0.2	0.1	0.1	0.0	0.0	0.0
Asset Management, Planning, & Sustainability	29.5	7.1	24.1%	0.6	2.0	0.3	0.7	0.6	1.3	0.7	0.4	0.1	0.1	0.3
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
SMR Consortium	25.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
General Council / Land	5.9	1.1	19.0%	0.1	0.3	0.0	0.1	0.1	0.2	0.1	0.1	0.0	0.0	0.1
Safety	8.0	1.9	23.2%	0.2	0.5	0.1	0.2	0.1	0.3	0.2	0.1	0.0	0.0	0.1
Corporate Information & Technology	117.5	27.0	23.0%	2.5	7.7	1.2	2.7	2.2	5.1	2.6	1.4	0.5	0.5	1.2
Human Resources	38.0	10.7	28.3%	1.0	3.1	0.5	1.1	0.9	2.0	1.0	0.6	0.2	0.2	0.5
Commercial & Industrial Operations	13.5	-	0.0%	-	-	-	-	-	-	-	-	-	-	-
Procurement & Supply Chain	41.3	10.1	24.6%	0.9	2.9	0.4	1.0	0.8	1.9	1.0	0.5	0.2	0.2	0.5
Total Support Group Expenses	313.3	62.5	19.9%	5.7	17.8	2.7	6.3	5.0	11.8	6.1	3.3	1.1	1.1	2.8
Total OM&A Expenses	986.6	187.0	19.0%	17.0	53.3	8.0	18.7	15.1	35.2	18.2	9.8	3.2	3.2	8.4

Schedule 2.25: Functional Classification of Financial Account Details – Distribution Depreciation & Depletion

Functionalization and Classification of Financial Account Details																				
DISTRIBUTION DEPRECIATION & DEPLETION																				
2027 Fiscal Test Embedded Cost of Service Study																				
(\$ Millions)																				
Asset Categories	Sask Power Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streetlights		
				Demand		Demand		Demand		Demand		Demand							Demand	
Generation Assets																				
Power Production	326.6	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Purchase Power Agreements (PPA)	54.1	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Coal Reserves	3.0	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Stand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Generation Assets	383.9	-	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission Assets																				
Transmission Assets	95.5	1.1	1.1%	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Transmission Assets	95.5	1.1	1.1%	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution Assets																				
Distribution Assets	188.0	188.0	100.0%	17.5	47.3	5.8	13.6	10.8	25.3	17.0	9.2	34.9	-	-	-	-	-	-	6.6	
Meters	7.7	7.7	100.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	
Instrument Transformers	1.6	1.6	100.0%	-	-	-	-	-	-	-	-	-	-	-	1.6	-	-	-	-	
Total Distribution Assets	197.4	197.4	100.0%	17.5	47.3	5.8	13.6	10.8	25.3	17.0	9.2	34.9	-	-	1.6	-	-	7.7	6.6	
General Plant Assets																				
Unused Land	(0.0)	(0.0)	19.0%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	-	(0.0)	
Right of Use Land	0.9	0.2	19.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0	
Buildings	18.4	4.9	26.9%	0.4	1.4	0.2	0.5	0.4	0.9	0.5	0.3	0.1	0.1	0.1	0.1	-	-	-	0.0	
Right of Use Buildings	2.3	0.6	27.2%	0.1	0.2	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0	
Office Furniture & Equipment	4.3	1.2	26.9%	0.1	0.3	0.0	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.0	0.0	-	-	-	0.0	
Vehicles & Equipment	15.8	7.1	45.1%	0.6	2.0	0.3	0.7	0.6	1.3	0.7	0.4	1.1	0.7	0.4	0.1	-	-	-	0.0	
Computer Development & Equipment	41.8	9.6	22.9%	0.9	2.7	0.4	1.0	0.8	1.8	0.9	0.5	0.2	0.0	0.2	0.0	-	-	-	0.0	
Communication, Protection & Control	2.6	0.3	10.0%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.0	
Tools & Equipment	2.7	0.8	28.7%	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	-	-	-	0.0	
Total General Plant Assets	88.7	24.6	27.7%	2.2	7.0	1.1	2.5	2.0	4.6	2.4	1.3	0.4	-	0.4	-	-	-	-	1.1	
Total Depreciation & Depletion	765.5	223.1	29.1%	20.8	54.4	6.9	16.1	12.8	29.9	19.4	10.5	35.3	1.6	-	1.6	-	7.7	7.7	-	

Schedule 2.26: Functional Classification of Financial Account Details – Distribution Other Income

Functionalization and Classification of Financial Account Details													
DISTRIBUTION OTHER INCOME													
2027 Fiscal Test Embedded Cost of Service Study													
(\$ Millions)													
Expense Categories	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers	
				Demand		Demand		Demand	Customer	Demand	Customer	Demand	Customer
Other Income													
Customer Services Payment Charges	(8.3)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Meter Reading	(2.2)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Transmission	(4.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Distribution	(7.7)	(7.7)	100.0%	(0.7)	(0.3)	(2.2)	(2.2)	(0.8)	(1.4)	(0.6)	(0.4)	(0.1)	(0.3)
Miscellaneous Other Income	(2.8)	(0.5)	19.0%	(0.0)	(0.0)	(0.2)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)
Customer Contribution Revenue	(123.9)	(60.3)	48.7%	(0.0)	(0.8)	(1.8)	(1.8)	(1.8)	(5.1)	(2.2)	(0.0)	(44.7)	(3.9)
Green Power Premium	(0.0)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Flyash Sales	(11.1)	-	0.0%	-	-	-	-	-	-	-	-	-	-
CO2 Sales & Penalties	(18.6)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-	-	-	-	-
Total Other Income	(179.4)	(68.5)	38.2%	(0.7)	(1.1)	(4.2)	(4.2)	(2.6)	(6.7)	(2.9)	(0.4)	(44.8)	(4.3)

Schedule 2.30: Functional Classification of Financial Account Details – Customer Service

Functionalization and Classification of Financial Account Details CUSTOMER SERVICE Related Costs 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Rate Base and Expense Categories	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Basis of Classification	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Rate Base										
Plant in Service (Schedule 2.31)	23,451.5	226.9	1.0%	Functional Class of PIS	21.7	45.1	11.1	58.4	80.2	10.3
Accumulated Depreciation (Schedule 2.32)	(10,621.7)	(76.9)	0.7%	Functional Class of Accum. Depr'n	(9.6)	(14.2)	(3.4)	(21.1)	(25.2)	(3.4)
Allowance For Working Capital	137.5	11.8	8.6%	12.50% of OM&A and Taxes	1.1	2.4	0.6	3.0	4.2	0.5
Inventories (Schedule 2.33)	454.5	(0.1)	0.0%	Functional Class of Inventories	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Other Assets (Schedule 2.33)	88.2	4.4	5.0%	Functional Classification of Other Assets	0.4	0.9	0.2	1.1	1.6	0.2
Total Rate Base	13,510.0	166.0	1.2%		13.6	34.1	8.5	41.5	60.7	7.6
Revenue Requirement										
Fuel Expense SaskPower Units	640.3	-	0.0%	Functional Class of Fuel Exp.	-	-	-	-	-	-
Purchased Power & Import	308.1	-	0.0%	Functional Class of PP, Import & NP Fee	-	-	-	-	-	-
Export & Net Electricity Trading Revenue (Credit)	(64.7)	-	0.0%	Functional Class of Exports	-	-	-	-	-	-
Operating, Maintenance & Administration (Schedule 2.34)	986.6	93.2	9.4%	Functional Class of OM&A	8.7	18.7	4.6	23.9	33.2	4.1
Depreciation & Depletion (Schedule 2.35)	765.5	10.5	1.4%	Functional Class of Depr'n & Depletion	1.1	2.0	0.5	2.8	3.6	0.5
Corporate Capital Tax	75.6	0.9	1.2%	Functional Class of Corp. Capital Tax	0.1	0.2	0.0	0.2	0.3	0.0
Grants in Lieu of Taxes	36.6	-	0.0%	Functional Class of Grants in Lieu of Taxes	-	-	-	-	-	-
Miscellaneous Tax	1.0	-	0.0%	Functional Class of Misc. Tax	-	-	-	-	-	-
Other Income (Credit) (Schedule 2.36)	(179.4)	(10.8)	6.0%	Functional Class of Other Income	(0.0)	(2.3)	(5.5)	(2.8)	(0.1)	(0.0)
Return on Rate Base @ 4.72%	637.2	7.8	1.2%	Rate Base	0.6	1.6	0.4	2.0	2.9	0.4
Total Revenue Requirement	3,206.8	101.6	3.2%		10.5	20.2	0.0	26.0	39.9	5.0

Schedule 2.31: Functional Classification of Financial Account Details – Customer Services Plant in Service

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES PLANT IN SERVICE 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Generation Assets									
Power Production	10,062.8	-	0.0%	-	-	-	-	-	-
Power Production - PPA	1,218.4	-	0.0%	-	-	-	-	-	-
Coal Reserves	77.8	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	6.0	-	0.0%	-	-	-	-	-	-
Total Generation Assets	11,365.0	-	0.0%	-	-	-	-	-	-
Transmission Assets									
Transmission Assets	3,973.2	-	0.0%	-	-	-	-	-	-
Total Transmission Assets	3,973.2	-	0.0%	-	-	-	-	-	-
Distribution Assets									
Distribution Assets	6,153.7	-	0.0%	-	-	-	-	-	-
Meters	155.1	-	0.0%	-	-	-	-	-	-
Instrument Transformers	26.5	-	0.0%	-	-	-	-	-	-
Total Distribution Assets	6,335.4	-	0.0%	-	-	-	-	-	-
General Plant Assets									
Unused Land	2.3	0.2	9.4%	0.0	0.0	0.0	0.1	0.1	0.0
Right of Use Land	11.2	1.1	9.4%	0.1	0.2	0.1	0.3	0.4	0.0
Buildings	786.0	143.8	18.3%	9.6	30.6	7.7	34.6	54.6	6.7
Right of Use Buildings	8.6	1.6	18.8%	0.1	0.3	0.1	0.4	0.6	0.1
Office Furniture & Equipment	68.6	12.6	18.3%	0.8	2.7	0.7	3.0	4.8	0.6
Vehicles & Equipment	285.4	21.1	7.4%	5.8	2.5	0.4	7.6	4.2	0.6
Computer Development & Equipment	443.9	43.2	9.7%	4.1	8.6	2.1	11.1	15.3	1.9
Communication, Protection & Control	144.8	2.2	1.6%	0.8	0.1	-	0.9	0.2	0.3
Tools & Equipment	27.0	1.1	4.1%	0.4	0.1	-	0.5	0.1	0.0
Total General Plant Assets	1,777.9	226.9	12.8%	21.7	45.1	11.1	58.4	80.2	10.3
Total Plant In Service	23,451.5	226.9	1.0%	21.7	45.1	11.1	58.4	80.2	10.3

Schedule 2.32: Functional Classification of Financial Account Details – Customer Services Accumulated Depreciation

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES ACCUMULATED DEPRECIATION 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Generation Assets									
Power Production	(5,213.0)	-	0.0%	-	-	-	-	-	-
Power Production - PPA	(768.8)	-	0.0%	-	-	-	-	-	-
Coal Reserves	(55.7)	-	0.0%	-	-	-	-	-	-
Shand Greenhouse	(4.6)	-	0.0%	-	-	-	-	-	-
Total Generation Assets	(6,042.1)	-	0.0%	-	-	-	-	-	-
Transmission Assets									
Transmission Assets	(1,259.1)	-	0.0%	-	-	-	-	-	-
Total Transmission Assets	(1,259.1)	-	0.0%	-	-	-	-	-	-
Distribution Assets									
Distribution Assets	(2,412.9)	-	0.0%	-	-	-	-	-	-
Meters	(77.3)	-	0.0%	-	-	-	-	-	-
Instrument Transformers	(17.8)	-	0.0%	-	-	-	-	-	-
Total Distribution Assets	(2,508.0)	-	0.0%	-	-	-	-	-	-
General Plant Assets									
Unused Land	-	-	0.0%	-	-	-	-	-	-
Right of Use Land	(5.4)	(0.5)	9.4%	(0.0)	(0.1)	(0.0)	(0.1)	(0.2)	(0.0)
Buildings	(112.0)	(18.9)	16.9%	(1.3)	(4.0)	(1.0)	(4.6)	(7.2)	(0.9)
Right of Use Buildings	(7.3)	(1.4)	18.8%	(0.1)	(0.3)	(0.1)	(0.3)	(0.5)	(0.1)
Office Furniture & Equipment	(41.9)	(7.1)	16.9%	(0.5)	(1.5)	(0.4)	(1.7)	(2.7)	(0.3)
Vehicles & Equipment	(169.1)	(12.7)	7.5%	(3.5)	(1.5)	(0.2)	(4.6)	(2.5)	(0.4)
Computer Development & Equipment	(345.7)	(33.7)	9.8%	(3.3)	(6.7)	(1.6)	(8.7)	(11.9)	(1.5)
Communication, Protection & Control	(109.7)	(1.8)	1.6%	(0.6)	(0.1)	-	(0.7)	(0.2)	(0.2)
Tools & Equipment	(21.5)	(0.8)	3.8%	(0.3)	(0.1)	-	(0.3)	(0.1)	(0.0)
Total General Plant Assets	(812.5)	(76.9)	9.5%	(9.6)	(14.2)	(3.4)	(21.1)	(25.2)	(3.4)
Total Accumulated Depreciation	(10,621.7)	(76.9)	0.7%	(9.6)	(14.2)	(3.4)	(21.1)	(25.2)	(3.4)

Schedule 2.33: Functional Classification of Financial Account Details – Customer Services Inventories/Other Assets

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES INVENTORIES 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Inventories									
Power Production - Repair Stores	145.6	-	0.0%	-	-	-	-	-	-
Power Production - Fuel	57.4	-	0.0%	-	-	-	-	-	-
Transmission & Distribution	252.9	-	0.0%	-	-	-	-	-	-
Miscellaneous (Computers, Power Shop)	(1.4)	(0.1)	9.4%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Inventories	454.5	(0.1)	0.0%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES OTHER ASSETS 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Other Assets									
Deferred Assets / Prepaid Expenses - Coal Mine / Natural Gas	36.3	-	0.0%	-	-	-	-	-	-
Intangible Assets	-	-	0.0%	-	-	-	-	-	-
Prepaid Expenses - Insurance	5.8	0.0	0.6%	0.0	0.0	-	0.0	0.0	0.0
Miscellaneous Prepaid Expenses	46.2	4.4	9.4%	0.4	0.9	0.2	1.1	1.6	0.2
Total Other Assets	88.2	4.4	5.0%	0.4	0.9	0.2	1.1	1.6	0.2

Schedule 2.34: Functional Classification of Financial Account Details – Customer Services OM&A Expenses

Functionalization and Classification of Financial Account Details									
CUSTOMER SERVICES OM&A EXPENSES									
2027 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
Generation Expenses				Customer	Customer	Customer	Customer	Customer	Customer
Power Plant Operation	302.3	-	0.0%	-	-	-	-	-	-
Power Production Overhead	40.8	-	0.0%	-	-	-	-	-	-
Purchase Power Agreements (PPA)	18.5	-	0.0%	-	-	-	-	-	-
Total Generation Expenses	361.5	-	0.0%	-	-	-	-	-	-
Transmission & Distribution Expenses									
Planning Support	25.1	0.3	1.1%	-	-	-	-	-	0.3
Transmission Including 230/138 & 72 kV Radials	69.8	-	0.0%	-	-	-	-	-	-
Distribution	124.4	-	0.0%	-	-	-	-	-	-
Customer Services	9.1	9.1	100.0%	-	1.0	-	6.4	1.6	-
Metering Services	5.8	5.8	100.0%	5.8	-	-	-	-	-
Total Transmission & Distribution Expenses	234.1	15.1	6.5%	5.8	1.0	-	6.4	1.6	0.3
Customer Services Expenses									
Meter Reading	12.9	12.9	100.0%	-	12.9	-	-	-	-
Billing Services	3.5	3.5	100.0%	-	-	3.5	-	-	-
Collections/Special Collections	1.7	1.7	100.0%	-	-	-	1.7	-	-
Bad Debt Expense	9.0	9.0	100.0%	-	-	-	9.0	-	-
Marketing & Sales	2.8	2.8	100.0%	-	-	-	-	-	2.8
Demand Side Management	24.4	-	0.0%	-	-	-	-	-	-
Customer Service	23.3	23.3	100.0%	-	-	-	-	23.3	-
Total Customer Services Expenses	77.6	53.2	68.6%	-	12.9	3.5	10.8	23.3	2.8
Support Group Expenses									
President / Board	2.6	0.2	9.4%	0.0	0.0	0.0	0.1	0.1	0.0
Corporate & Financial Services (C&FS)	11.8	1.3	10.6%	0.1	0.2	0.1	0.3	0.4	0.1
C&FS - Insurance Premiums & Insurable Losses	20.1	0.1	0.6%	0.0	0.0	-	0.1	0.0	0.0
Asset Management, Planning, & Sustainability	29.5	1.6	5.5%	0.3	0.2	0.1	0.5	0.4	0.1
Integrated Carbon Capture & Sequestration	-	-	0.0%	-	-	-	-	-	-
SMR Consortium	25.0	-	0.0%	-	-	-	-	-	-
General Council / Land	5.9	0.6	9.4%	0.1	0.1	0.0	0.1	0.2	0.0
Safety	8.0	0.7	8.5%	0.1	0.1	0.0	0.2	0.2	0.0
Corporate Information & Technology	117.5	12.4	10.5%	1.3	2.4	0.6	3.2	4.3	0.5
Human Resources	38.0	3.6	9.4%	0.5	0.6	0.1	1.0	1.1	0.1
Commercial & Industrial Operations	13.5	-	0.0%	-	-	-	-	-	-
Procurement & Supply Chain	41.3	4.4	10.6%	0.5	0.8	0.2	1.2	1.5	0.2
Total Support Group Expenses	313.3	24.8	7.9%	2.9	4.7	1.1	6.7	8.3	1.1
Total OM&A Expenses	986.6	93.2	9.4%	8.7	18.7	4.6	23.9	33.2	4.1

Schedule 2.35: Functional Classification of Financial Account Details – Customer Services Depreciation & Depletion

Functionalization and Classification of Financial Account Details CUSTOMER SERVICES DEPRECIATION & DEPLETION 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)										
Asset Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning	
Generation Assets										
Power Production	326.6	-	0.0%	-	-	-	-	-	-	-
Purchase Power Agreements (PPA)	54.1	-	0.0%	-	-	-	-	-	-	-
Coal Reserves	3.0	-	0.0%	-	-	-	-	-	-	-
Shand Greenhouse	0.2	-	0.0%	-	-	-	-	-	-	-
Total Generation Assets	383.9	-	0.0%	-	-	-	-	-	-	-
Transmission Assets										
Transmission Assets	95.5	-	0.0%	-	-	-	-	-	-	-
Total Transmission Assets	95.5	-	0.0%	-	-	-	-	-	-	-
Distribution Assets										
Distribution Assets	188.0	-	0.0%	-	-	-	-	-	-	-
Meters	7.7	-	0.0%	-	-	-	-	-	-	-
Instrument Transformers	1.6	-	0.0%	-	-	-	-	-	-	-
Total Distribution Assets	197.4	-	0.0%	-	-	-	-	-	-	-
General Plant Assets										
Unused Land	(0.0)	(0.0)	9.4%	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Right of Use Land	0.9	0.1	9.4%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Buildings	18.4	3.4	18.7%	0.2	0.7	0.2	0.8	1.3	0.2	0.2
Right of Use Buildings	2.3	0.4	18.8%	0.0	0.1	0.0	0.1	0.2	0.0	0.0
Office Furniture & Equipment	4.3	0.8	18.7%	0.1	0.2	0.0	0.2	0.3	0.0	0.0
Vehicles & Equipment	15.8	1.3	8.0%	0.3	0.2	0.0	0.4	0.3	0.0	0.0
Computer Development & Equipment	41.8	4.4	10.4%	0.4	0.9	0.2	1.1	1.5	0.2	0.2
Communication, Protection & Control	2.6	0.0	1.4%	0.0	0.0	-	0.0	0.0	0.0	0.0
Tools & Equipment	2.7	0.1	3.5%	0.0	0.0	-	0.0	0.0	0.0	0.0
Total General Plant Assets	88.7	10.5	11.9%	1.1	2.0	0.5	2.8	3.6	0.5	0.5
Total Depreciation & Depletion	765.5	10.5	1.4%	1.1	2.0	0.5	2.8	3.6	0.5	0.5

Schedule 2.36: Functional Classification of Financial Account Details – Customer Services Other Income

Functionalization and Classification of Financial Account Details									
CUSTOMER SERVICES OTHER INCOME									
2027 Fiscal Test Embedded Cost of Service Study									
(\$ Millions)									
Expense Categories	SaskPower Total	Customer Services Total	Customer Services as a % of SaskPower Total	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
				Customer	Customer	Customer	Customer	Customer	Customer
Other Income									
Customer Services Payment Charges	(8.3)	(8.3)	100.0%	-	-	(5.5)	(2.8)	-	-
Meter Reading	(2.2)	(2.2)	100.0%	-	(2.2)	-	-	-	-
Transmission	(4.0)	-	0.0%	-	-	-	-	-	-
Distribution	(7.7)	-	0.0%	-	-	-	-	-	-
Miscellaneous Other Income	(2.8)	(0.3)	9.4%	(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
Customer Contribution Revenue	(123.9)	-	0.0%	-	-	-	-	-	-
Green Power Premium	(0.0)	-	0.0%	-	-	-	-	-	-
Flyash Sales	(11.1)	-	0.0%	-	-	-	-	-	-
CO2 Sales & Penalties	(18.6)	-	0.0%	-	-	-	-	-	-
Renewable Energy Credits	(0.8)	-	0.0%	-	-	-	-	-	-
Total Other Income	(179.4)	(10.8)	6.0%	(0.0)	(2.3)	(5.5)	(2.8)	(0.1)	(0.0)

Schedule 3.0: SaskPower Allocation Methodology Summary



SaskPower Functionalization	SaskPower Classification	SaskPower Sub-Functionalization	Allocation Methodology	# of Years of Data For Large Customer (s)
GENERATION	Demand	Load, Losses and Ancillary Services	Coincident Peak Method (ZCP) - at output of Generation and step up transformation.	5
	Energy	Load and Losses	Energy plus Losses.	N/A
TRANSMISSION	DEMAND	Main Grid	Coincident Peak Method (ZCP) - at output of transmission.	5
		230kV & 138kV Radials	Coincident Peak Method (ZCP) - at output of common 230 kV Radials.	5
		138/72kV Substations	Coincident Peak Method (ZCP) - at output of substations.	5
		72kV Radials	Coincident Peak Method (ZCP) - at output of common 72kV radials.	5
DISTRIBUTION	DEMAND	Area Substations - Demand	Coincident Peak Method (ZCP) - at output of substations.	5
		Distribution Mains - Demand	Coincident Peak Method (ZCP) - at output of distribution mains.	5
		Urban Laterals - Demand	Coincident Peak Method (ZCP) - at output of urban laterals.	5
		Rural Laterals - Demand	Coincident Peak Method (ZCP) - at output of rural laterals.	N/A
	CUSTOMER	Transformers - Demand	Non Coincident Peak (NCP) - at output of rural laterals.	5
		Urban Laterals - Customer	Number of urban customers supplied through laterals.	N/A
		Rural Laterals - Customer	Number of rural customers supplied through laterals.	5
		Transformers - Customer	Number of customers supplied through laterals.	N/A
		Services - Customer	Direct to classes which are using services.	N/A
		Meters - Customer	Number of metered customers weighted by installed cost of a meter.	N/A
CUSTOMER SERVICES	CUSTOMER	Streetlights - Customer	Direct to Streetlight Class.	N/A
		Customer Service	Weighted number of customers.	N/A
	DEMAND	Customer Contributions	Direct to classes which made contribution.	N/A
		Interruptible Adjustment	Coincident Peak Method (ZCP).	5

ZCP METHOD

The ZCP (coincident peak) method, allocates costs to rate classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peak. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

NCP METHOD

The NCP-MDD method allocates rate base and expense responsibilities based on the ratio of the class' non coincident peak maximum demand, to the sum of all the class non coincident peaks, similarly determined.

Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation 2027 Fiscal Test Embedded Cost of Service Study							
Customer Class	Energy Sales GWH	NCP Demand KW	MDD Demand KW	CP Demand KW	NCP Load Factor ¹	MDD Load Factor ²	CP Load Factor ³
Residential	3,291	3,115,500	761,594	662,526	12.06%	49.33%	56.71%
Farms	1,299	809,764	261,448	217,568	18.31%	56.70%	68.13%
Commercial	3,768	1,296,027	617,829	573,626	33.19%	69.61%	74.98%
Power	11,489	2,027,814	1,556,357	1,382,752	64.68%	84.27%	94.85%
Oilfields	4,498	785,752	562,942	526,710	65.34%	91.20%	97.48%
Reseller	1,146	232,975	232,975	203,429	56.13%	56.13%	64.28%
Total	25,489	8,267,832	3,993,145	3,566,611	35.19%	72.87%	81.58%

1 - NCP Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (NCP Demand * 8760)

2 - MDD Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (MDD Demand * 8760)

3 - CP Load Factor is calculated as follows: (Energy Sales * 1,000,000) / (CP Demand * 8760)

Schedule 5.0: Allocation Factors by Customer Class – Generation

Allocation Factors by Customer Class GENERATION Related Costs 2027 Fiscal Test Embedded Cost of Service Study																								
Customer Class	Load ¹		Load ²	Losses ³		Losses ⁴		Scheduling & Dispatch ³		Regulation & Frequency Response ³		Spinning Reserve ³		Supplementary Reserve ³		Planning Reserve ³		Reactive Supply ³		Grants in Lieu of Taxes ⁵		Interruptible Adjustment ³		
	Demand	Energy		Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	Demand	Energy	
Residential	18.6%	12.9%		27.9%	21.3%			19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	19.5%	21.7%	19.5%	19.5%	19.5%	
Farms	6.1%	5.1%		8.6%	7.6%			6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.6%	6.3%	6.3%	6.3%	
Commercial	16.1%	14.8%		23.6%	23.6%			16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	18.8%	16.8%	16.8%	16.8%	
Power	38.8%	45.1%		18.3%	21.5%			36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	36.7%	32.5%	36.7%	36.7%	36.7%	
Oilfields	14.8%	17.6%		19.2%	24.1%			15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	15.2%	16.8%	15.2%	15.2%	15.2%	
Reseller	5.7%	4.5%		2.5%	2.0%			5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	3.5%	5.4%	5.4%	5.4%	
Total	100.0%	100.0%		100.0%	100.0%			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	

¹Based on Coincident Peak (ZCP) at the meter.

²Based on actual energy consumption at the meter.

³Based on Coincident Peak (ZCP) & losses.

⁴Based on energy losses.

⁵Based on Sales Revenue.

Schedule 5.1: Allocation Factors by Customer Class – Transmission

Allocation Factors by Customer Class TRANSMISSION Related Costs 2027 Fiscal Test Embedded Cost of Service Study				

Customer Class	Main Grid	230kV & 138kV Radials	138/72kV Substations	72kV Radials
	Demand	Demand	Demand	Demand
Residential	19.5%	13.9%	31.2%	31.2%
Farms	6.3%	4.6%	10.0%	10.0%
Commercial	16.8%	11.8%	27.2%	27.2%
Power	36.7%	56.1%	8.0%	8.0%
Oilfields	15.2%	11.5%	23.1%	23.1%
Reseller	5.4%	2.2%	0.5%	0.5%
Total	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on Coincident Peak (2CP) & losses.

Schedule 5.2: Allocation Factors by Customer Class – Distribution

Allocation Factors by Customer Class DISTRIBUTION Related Costs 2027 Fiscal Test Embedded Cost of Service Study																		
Customer Class	Area Substations ¹	Distribution Mains ¹		Urban Laterals ¹	Urban Laterals ²	Rural Laterals ¹	Rural Laterals ³	Transformers ⁴	Transformers ⁵	Services ⁶	Instrument Transformers ⁷	Amortization Customer Contributions ⁸	Meters ⁹	Streetlights ¹⁰				
		Demand	Demand															
Residential	33.8%	33.9%	25.8%	88.0%	10.1%	44.2%	28.1%	74.9%	31.3%	0.0%	21.6%	57.2%	0.0%					
Farms	10.9%	10.9%	0.0%	0.0%	18.9%	34.6%	12.5%	10.4%	11.3%	11.3%	0.5%	29.6%	10.3%	0.0%				
Commercial	28.5%	28.6%	74.2%	12.0%	18.9%	10.1%	32.1%	11.4%	39.4%	39.4%	87.2%	33.4%	24.4%	100.0%				
Power	2.3%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%	0.0%	1.1%	0.0%				
Oilfields	24.3%	24.4%	0.0%	0.0%	52.2%	11.1%	27.2%	3.3%	18.0%	18.0%	1.0%	15.4%	6.8%	0.0%				
Reseller	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.1%	0.0%				
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%				

¹ Based on Coincident Peak (COP) & losses.

² Based on the number of urban customers in each customer class. Urban streetlights are based on 6 lights per circuit.

³ Based on the number of rural customers in each customer class. Rural streetlights are based on 3 lights per circuit.

⁴ Based on Non Coincident Peak (NCP) & losses.

⁵ Based on the number of customers with transformer-related equipment in each customer class. Streetlights are based on 6(urban) & 3(rural) lights per circuit.

⁶ Based on the number of customers in each customer class supplied through services weighted by installed cost of a service.

⁷ Based on the number of customers with transformer-related equipment in each customer class.

⁸ Based on customer contributions in each customer class.

⁹ Based on the new capital cost of meters and instrument transformers multiplied by the number of customers in the customer class.

¹⁰ Direct to the streetlight class.

Schedule 5.3: Allocation Factors by Customer Class – Customer Service

Allocation Factors by Customer Class CUSTOMER SERVICE Related Costs 2027 Fiscal Test Embedded Cost of Service Study						
Customer Class	Metering Services	Meter Reading	Billing & Customer Accounts	Customer Collections	Service & Support	Customer Strategy & Planning
	Customer	Customer	Customer	Customer	Customer	Customer
Residential	20.4%	73.2%	56.0%	87.0%	67.9%	11.8%
Farms	3.9%	15.8%	10.1%	6.0%	12.1%	9.1%
Commercial	27.6%	6.8%	18.0%	6.0%	11.7%	19.0%
Power	23.0%	0.0%	2.3%	0.0%	2.7%	32.2%
Oilfields	24.6%	4.2%	13.5%	1.0%	5.6%	27.1%
Reseller	0.6%	0.0%	0.1%	0.0%	0.1%	0.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note: All allocation factors based on the department responsible's estimate of labour time spent on each customer class.

Schedule 6.0: Functional Classification of Revenue Requirement by Customer Class – Generation

Functionalized & Classified Revenue Requirement by Customer Class																			
GENERATION Related Costs																			
2027 Fiscal Test Embedded Cost of Service Study																			
(\$ Millions)																			
Customer Class	SasPower Total	Generation Total	Generation as a % of SasPower Total	Load		Load	Losses	Scheduling & Dispatch		Regulation & Frequency Response	Spinning Reserve		Supplementary Reserve	Planning Reserve		Reactive Supply	Grants in Lieu of Taxes		Interruptible Adjustment
				Demand	Energy			Demand	Energy		Demand	Energy		Demand	Energy		Demand	Energy	
Residential	705.5	339.8	48.3%	87.9	179.7	13.3	13.9	2.7	1.7	5.0	7.5	9.9	4.2	8.0	-	-	-	-	-
Farms	221.3	123.5	55.8%	28.9	70.9	4.1	7.1	0.9	0.6	1.6	2.4	3.2	1.4	2.4	-	-	-	-	-
Commercial	584.1	348.9	59.7%	76.1	205.7	11.2	22.1	2.3	1.5	4.3	6.5	8.6	3.6	6.9	-	-	-	-	-
Power	1,033.0	910.2	88.1%	183.6	627.3	8.7	20.2	5.0	3.2	9.4	14.1	18.7	7.9	12.0	-	-	-	-	-
Oilfields	548.4	377.5	68.8%	69.9	245.6	9.2	22.5	2.1	1.3	3.9	5.9	7.7	3.3	6.2	-	-	-	-	-
Reseller	116.6	102.4	87.9%	27.0	62.5	1.2	1.8	0.7	0.3	1.4	2.1	2.7	1.2	1.3	-	-	-	-	-
Total	3,206.8	2,202.3	68.7%	473.5	1,391.8	47.7	93.6	13.7	8.7	25.7	38.5	50.8	21.5	36.8	-	-	-	-	-

Schedule 6.1: Functional Classification of Revenue Requirement by Customer Class – Transmission

Functionalized & Classified Revenue Requirement by Customer Class											
TRANSMISSION Related Costs											
2027 Fiscal Test Embedded Cost of Service Study											
(\$ Millions)											
Customer Class	SaskPower Total	Transmission Total	Transmission as a % of SaskPower Total	Main Grid		230 kV Radials		230/138 kV Substations		138 kV Lines Radials	
				Demand		Demand		Demand		Demand	
Residential	703.5	70.4	10.0%	46.0		5.1		7.1		12.2	
Farms	221.3	22.9	10.3%	15.0		1.7		2.3		3.9	
Commercial	584.1	60.8	10.4%	39.7		4.4		6.2		10.6	
Power	1,033.0	112.3	10.9%	86.6		20.8		1.8		3.1	
Oilfields	548.4	54.4	9.9%	35.8		4.3		5.2		9.0	
Reseller	116.6	13.8	11.9%	12.7		0.8		0.1		0.2	
Total	3,206.8	334.6	10.4%	235.7		37.0		22.7		39.1	

Schedule 6.2: Functional Classification of Revenue Requirement by Customer Class – Distribution

Functionalized & Classified Revenue Requirement by Customer Class																		
DISTRIBUTION Related Costs																		
2027 Fiscal Test Embedded Cost of Service Study																		
(\$ Millions)																		
Customer Class	SaskPower Total	Distribution Total	Distribution as a % of SaskPower Total	Area Substations		Distribution Mains		Urban Laterals		Rural Laterals		Transformers		Services	Instrument Transformers	Amortization Customer Contributions	Meters	Streetlights
				Demand		Demand		Demand	Customer	Demand	Customer	Demand	Customer					
Residential	703.5	226.0	32.1%	19.6	55.9	5.2	41.4	3.7	37.8	15.9	22.8	16.9	-	-	-	-	6.8	-
Farms	221.3	64.5	29.1%	6.3	18.0	-	-	6.9	29.6	7.1	3.2	(7.9)	0.0	-	-	-	3.2	-
Commercial	584.1	163.0	27.9%	16.6	47.1	14.9	5.6	6.9	8.7	18.2	3.5	18.5	1.8	-	-	-	2.9	18.2
Power	1,033.0	5.4	0.5%	1.3	3.7	-	-	-	-	-	-	-	0.2	-	-	-	0.1	-
Oilfields	548.4	109.2	19.9%	14.1	40.3	-	-	19.1	9.5	15.4	1.0	9.0	-	-	-	-	0.8	-
Retailer	116.6	0.2	0.2%	0.2	-	-	-	-	-	-	-	-	-	-	-	-	0.0	-
Total	3,206.8	568.3	17.7%	58.2	165.0	20.1	47.0	36.7	85.6	56.6	30.5	36.5	2.1	-	-	-	11.9	18.2

Schedule 6.3: Functional Classification of Revenue Requirement by Customer Class – Customer Service

Functionalized & Classified Revenue Requirement by Customer Class CUSTOMER SERVICE Related Costs 2027 Fiscal Test Embedded Cost of Service Study (\$ Millions)									
Customer Class	SaskPower Total	Customer Service Total	Customer Service as a % of SaskPower Total	Metering Services Customer	Meter Reading Customer	Billing & Customer Accounts Customer	Customer Collections Customer	Service & Support Customer	Customer Strategy & Planning Customer
Residential	703.5	67.3	9.6%	2.1	14.8	0.0	22.6	27.1	0.6
Farms	221.3	10.4	4.7%	0.4	3.2	0.0	1.6	4.8	0.5
Commercial	584.1	11.4	2.0%	2.9	1.4	0.0	1.6	4.7	0.9
Power	1,033.0	5.1	0.5%	2.4	0.0	0.0	0.0	1.1	1.6
Oilfields	548.4	7.2	1.3%	2.6	0.8	0.0	0.3	2.2	1.3
Reseller	116.6	0.1	0.1%	0.1	0.0	0.0	0.0	0.0	0.0
Total	3,206.8	101.6	3.2%	10.5	20.2	0.0	26.0	39.9	5.0

Schedule 7.0: Customer Data for Rate Design

Customer Data				
2027 Fiscal Test Embedded Cost of Service Study				
Customer Class	Average Annual # of Accounts	Annual Revenue (\$)	Annual Sales @ Meter (MWh)	Annual Billing Demand @ Meter (kVa)
Residential	426,255	694,778,646	3,291,029	-
Farms	58,878	213,121,237	1,298,540	1,889,633
Commercial	66,115	603,946,584	3,767,645	10,990,523
Power	111	1,047,505,270	11,488,787	21,962,516
Oilfields	18,832	535,577,409	4,497,540	9,287,274
Reseller	3	111,895,854	1,145,508	2,201,121
Total	570,194	3,206,825,000	25,489,048	46,331,067

Section 9: Staff levels by division

FTEs

	2023-24	2024-25	2025-26
	Actual	Actual	Forecast
Pesident/Board	8.0	8.0	8.0
Operations Other	34.0	31.0	31.0
System Operations	111.0	127.0	135.7
Generation	649.0	675.0	709.7
Transmission & Distribution	792.0	830.0	853.3
Engineering & Construction	457.0	434.0	461.0
Nuclear Development	25.0	30.0	38.0
Asset Strategy & Planning	152.0	155.0	162.7
Technology	217.0	213.0	210.9
Finance	83.0	86.0	90.0
People, Safety & Corp Relations	184.0	189.0	191.9
Customer Exp & Procurement	244.0	242.0	262.8
Legal & Corporate Services	291.0	292.0	292.0
	3,247.0	3,312.0	3,447.0

Section 10: Report on implementation of previous Panel recommendations

Panel recommendations from 2022 and 2023 Rate Application

1. That SaskPower prepare public versions of its business plan, integrated resource plan and depreciation study as part of its future rate applications.

SaskPower response:

Business plan: SaskPower has provided detailed financial information in its rate application document for 2025-26 and 2026-27, including a listing of major capital projects in the short-term.

Integrated resource plan: SaskPower has completed extensive work on a public version of the Integrated Resource Plan. Over 60,000 people engaged with SaskPower through the process to date. SaskPower has updated the SRRP, and updates are publicly available on our website, saskpower.com. The release of the Long-term Supply Plan has been postponed due to the changing generation supply mix.

Depreciation study: The most recent review concluded in 2023. Since the report's completion, significant changes have been made to SaskPower's energy security strategy and future generation supply mix. The next external depreciation study is scheduled for 2028 and that version will be made available to the public.

2. That SaskPower complete an analysis of the potential impact of eliminating the price hedging element of its natural gas exposure management policy on the corporation's net income requirements at the time of the next application.

SaskPower response: SaskPower has completed the analysis. The analysis and the new hedging strategy has been provided to the SRRP.

3. That SaskPower continue to focus on limiting growth in OM&A per customer account to less than inflation and to continue to track and provide OM&A per residential customer for future applications.

SaskPower response: The OM&A per residential customer metric continues to be tracked and has been included in the rate application document.

4. That SaskPower provide a report in its next application that indicates how it achieved the contingency savings that was presented in the OM&A budget.

SaskPower response: The report has been provided to the SRRP.

Section 11: The most recent risk assessment for SPC

RISK MANAGEMENT

SaskPower operates in a complex and dynamic business environment. Significant pressures, uncertainties, and changes are occurring in the industry. As part of the strategic planning process, major challenges to our business have been identified which introduce a variety of risks and uncertainties that could impact the achievement of our business objectives. In addition to strategic risk, functional risks are identified, managed and to the extent possible mitigated through the Enterprise Risk Management (ERM) Program. These functional risks include: financial performance, operational performance, safety, compliance, and reputation. SaskPower's risk management responses are implemented in various ways, including through governance practices, policies, procedures, processes, and technologies. The ERM Program promotes a consistent and standard approach to risk identification, assessment, and management throughout the organization. Through the program, SaskPower's Board of Directors and Executive Members continue to identify and respond to developing and potential new risks. In this uncertain environment, corporate risk management efforts are aligned to allow SaskPower to continue to deliver reliable and affordable power in Saskatchewan.

ERM GOVERNANCE

Risk management is the responsibility of all employees and is an integral part of our culture. SaskPower's Board of Directors has overall responsibility for stewardship of the Corporation and the President and CEO has ultimate accountability for risk management, with support from Executive Members. Executive Members manage key business risks, including new and emerging risks and opportunities. The Audit & Finance Committee of the Board is responsible for overseeing the ERM framework, risk management policies, authorities, and accountabilities of shared risk management throughout SaskPower.

SaskPower's business divisions are responsible for managing day-to-day risks within their areas of responsibility. Project risks are the responsibility of project managers, with corresponding accountability to project boards and respective Executive Members.

TOP CORPORATE RISKS

Our company is challenged by regulatory requirements; early engagement with Indigenous and non-Indigenous communities on projects and initiatives planned to meet the needs of the electricity system; the need for new electricity supply; financial constraints; economic disruptors; evolving technologies; growing capital requirements; and the speed at which stakeholder and customers' expectations are changing. SaskPower annually identifies top corporate risks that could impact our company's corporate strategies and priorities; influence financial and operating results; and affect achievement of our business objectives.

SaskPower's risk portfolio evolves over time, with significant shifts to focus on key emerging issues and priority initiatives. Our company regularly undertakes routine and non-routine projects as well as strategic initiatives to meet evolving regulatory requirements, customer demands, and load conditions. These projects and initiatives involve significant investment and require strategic risk management to support investment decision making.

1. REGULATION

The Corporation is subject to extensive federal, provincial and municipal regulations. Failure to comply with these regulations could result in fines or other penalties.

SaskPower continues to assess the federal regulatory environment. Meanwhile, the Corporation has worked with the provincial government to streamline project permitting requirements through the Red Tape Reduction initiative. Additionally, the Corporation continues to assess the federal regulatory environment.

2. FINANCIAL SUSTAINABILITY

SaskPower's financial flexibility and capability are challenged by current economic conditions, growing capital requirements, increasing debt, and pressures to maintain competitive rates. SaskPower has a high fixed-cost structure driven by the capital-intensive nature of the electric utility business. SaskPower's business model needs to be agile enough to adapt to industry changes, including emissions requirements, rising costs, capital expenditures and customer self-generation. Key financial drivers include revenues which are impacted by load growth, provincial economic conditions, customer mix, and approved rate increases. The cost of fuel is driven by load growth, fuel mix, and the market price of fuel. Depreciation and finance charges are impacted by capital expenditures and the cost of borrowing.

SaskPower minimizes the impact of current financial constraints by implementing business optimization initiatives; using scenario-based budgeting and forecasting for business planning; prioritizing capital spending; engaging in cost-effective financing; diversifying the fuel mix; developing a rate management strategy; monitoring counterparty credit risk; validating load forecast assumptions; hedging natural gas requirements; maintaining rate competitiveness and identifying the most cost-effective supply options.

3. INFRASTRUCTURE, RELIABILITY, AND ENERGY SUPPLY

Significant capital spending is required to maintain system reliability, reduce risk of equipment failures, renew aging infrastructure, and accommodate growing demand for electricity. SaskPower's electricity supply infrastructure can be affected by age, insufficient capital investment, significant technological change, innovation, and growing customer demand and expectations. A large portion of SaskPower's critical generation, transmission and distribution assets are near or at the end of their expected service life.

Performance, reliability, and maximized uptime of existing generation, transmission, and distribution facilities are fundamental to maintaining a safe, continuous, and adequate supply of electricity. Information technology system requirements are evolving to manage the power system more efficiently and maintain acceptable security standards.

SaskPower manages fuel supply risks through strategies that include long-term natural gas transmission contracts; long-term coal contracts to address price, quality and security of supply; and feasibility study of small modular reactors using nuclear as a source fuel.

4. ENERGY POLICY

The Corporation is challenged as the utility industry is in the midst of a major infrastructure investment cycle within a shifting energy policy environment in North America and the world. The bulk of SaskPower infrastructure is either coming to the end of its useful life and needs to be renewed or replaced. The traditional electricity grid is evolving into a system in which automation, remote control, visibility, and customer participation are expected. Customers will become more integrated in the Corporation's network through customer-owned generation and energy management products by providing input on long-term decision making.

The Corporation has strategies to define the path forward within a changing energy policy environment, including a diverse supply plan. A cross-functional team works with various stakeholders to address disruption resulting from distributed and self-generation technologies. SaskPower continues to explore new opportunities for cogeneration with large industrial customers and nuclear generation options.

5. INDIGENOUS ENGAGEMENT

SaskPower interacts with a variety of Indigenous communities and Rights Holders within the scope of its operations. Indigenous expectations include greater transparency, involvement, and stewardship. Positive engagement through effective communication of SaskPower's needs and strategic direction helps our company achieve its objectives and deal with adversity or significant change when it impacts the organization and Indigenous stakeholders. SaskPower continues to facilitate engagement with Indigenous Rights Holders related to plans for the power system in Saskatchewan.

6. SECURITY

SaskPower business operations rely on information and operational technologies which need to be maintained, supported, protected, and secured while enabling appropriate access and ensuring reliability, confidentiality, integrity, and availability of associated systems and information. Demand for security capabilities will increase as threats continue to evolve.

SaskPower has established physical and cyber security controls to defend our servers, networks, and data from attack, damage, or unauthorized use. Identity and access management controls restrict unauthorized access of data and malicious manipulation of data by external or internal actors. Data loss prevention techniques have been deployed to identify, monitor, and prevent inappropriate sharing of sensitive and confidential information. System vulnerabilities are managed by hardening servers and encrypting mobile assets. SaskPower employees are equipped with various security awareness techniques and training to understand emerging phishing and artificial intelligence risks.

7. SAFETY

SaskPower operations can inherently impact the safety of employees, contractors, customers, and the general public. There are considerable hazards and risks associated with working on high voltage equipment, on equipment operated at a high temperature or pressure, at heights, with chemicals, and around large machines. SaskPower interacts with customers, contractors, and the public to inform them of potential safety issues.

SaskPower mitigation strategies include the integration of leadership competencies to foster and reinforce safe work practices. The Standard Protection Code and Standard Operating Procedures have been embedded in SaskPower's safety culture and operations. Contractors and employees are provided with safety orientations and learning opportunities for compliance with legislation and corporate safety requirements. Safety goals and the Corporate Balanced Scorecard Health & Safety Index are also incorporated into our company's performance management process. Risk-based asset maintenance programs at SaskPower include equipment inspection, replacement, and maintenance. The asset maintenance program is designed to reduce the risk of public injuries or fatalities. Partnerships are continuing with the Government of Saskatchewan Ministry of Agriculture and other public and private organizations to raise awareness of public safety in a way that will reduce farming and construction-related incidents.

8. PROJECT DELIVERY AND SUPPLY CHAIN

SaskPower has identified the need to invest significant amounts of capital in long-term projects to ensure continued reliability — this includes maintaining, upgrading, and expanding infrastructure. The Corporation continues to deliver on significant projects related to customer connects, service delivery improvements, refurbishment of existing infrastructure, and new supply options. All of these projects are competing for human resources as well as financial, operating, and capital resources. As well, new regulations, stakeholder expectations, and financial constraints place increasing demands on the company.

Delay or quality of material may result in not delivering projects on schedule or within budget, therefore increasing costs for the Corporation and potentially impacting reliability. SaskPower mitigation strategies include standardizing project delivery tools and governance methods; implementing vendor prequalification and provision for long-term goods and service contracts; tracking earned value metrics for each project; managing project risks through cross-functional risk committees; as well as comprehensive monitoring and reporting of project dependencies and outage scheduling.

9. PEOPLE AND SKILLS

Over the next decade, continued success will be tied to SaskPower's ability to train, attract, and retain sufficiently qualified staff to meet business needs. SaskPower will focus on succession planning, skillset gap analysis, retention strategies, targeted recruitment for in-demand occupations, and continuous improvement training. The Corporation is continuing to build partnerships with educational institutions and support apprenticeship programs to assist in meeting our workforce needs.

Section 12: Comparison of SPC rates/competitive factors relative to other Canadian Utilities

2024

Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2024



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Legal Deposit, Bibliothèque et Archives nationales du Québec, 4th quarter 2024
ISBN : 978-2-550-99040-6 (PDF v. ang.)
ISBN : 978-2-550-99039-0 (PDF v. fr.)

For more information, please call Hydro-Québec's Direction –
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Tel.: 514 798-1223, ext. 879-2081

This publication is available online at
www.hydroquebec.com/documents-data/official-publications.

Original document written in French.
Ce document est également publié en français.

2024G391A

INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial segments with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of the comparative analysis of prices in effect on April 1, 2024. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS^{1, 2}
(IN ¢/kWh)³



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2024.

2) Average prices excluding taxes.

3) In Canadian currency.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS^{1, 2}
(IN ¢/kWh)³



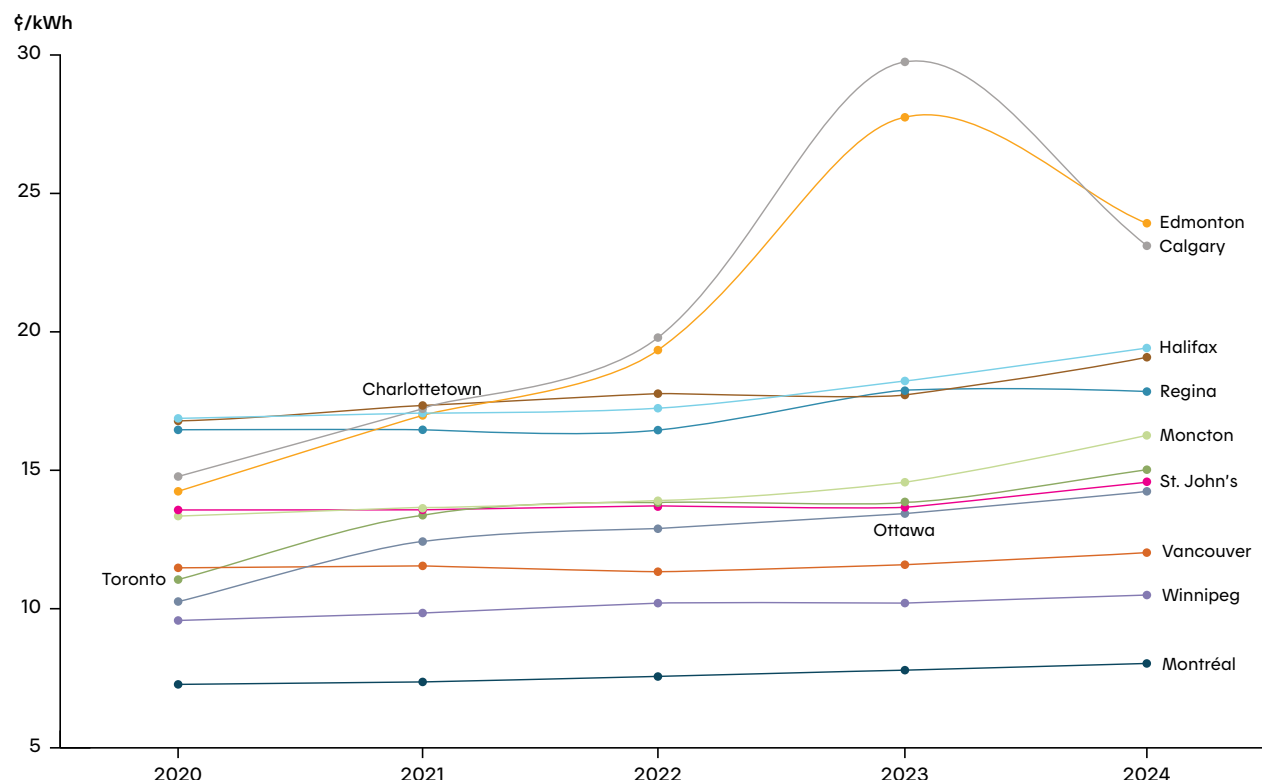
1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW;
rates in effect April 1, 2024.

2) Average prices excluding taxes.

3) In Canadian currency.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2020–2024^{1, 2, 3, 4}



AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh)^{1, 2, 3, 4}

	2020	2021	2022	2023	2024
Canadian Cities					
● Montréal, QC	7.30	7.39	7.59	7.81	8.05
● Calgary, AB	14.83	17.26	19.94	29.80	23.17
● Charlottetown, PE	16.83	17.38	17.78	17.78	19.13
● Edmonton, AB	14.29	16.99	19.48	27.78	23.98
● Halifax, NS	16.89	17.09	17.30	18.27	19.46
● Moncton, NB	13.42	13.66	13.94	14.61	16.30
● Ottawa, ON	10.29	12.45	12.94	13.48	14.28
● Regina, SK	16.51	16.51	16.51	17.89	17.89
● St. John's, NL	13.60	13.60	13.76	13.73	14.62
● Toronto, ON	11.10	13.43	13.88	13.88	15.06
● Vancouver, BC	11.51	11.58	11.39	11.62	12.06
● Winnipeg, MB	9.60	9.87	10.24	10.24	10.53

1) For a monthly consumption of 1,000 kWh.

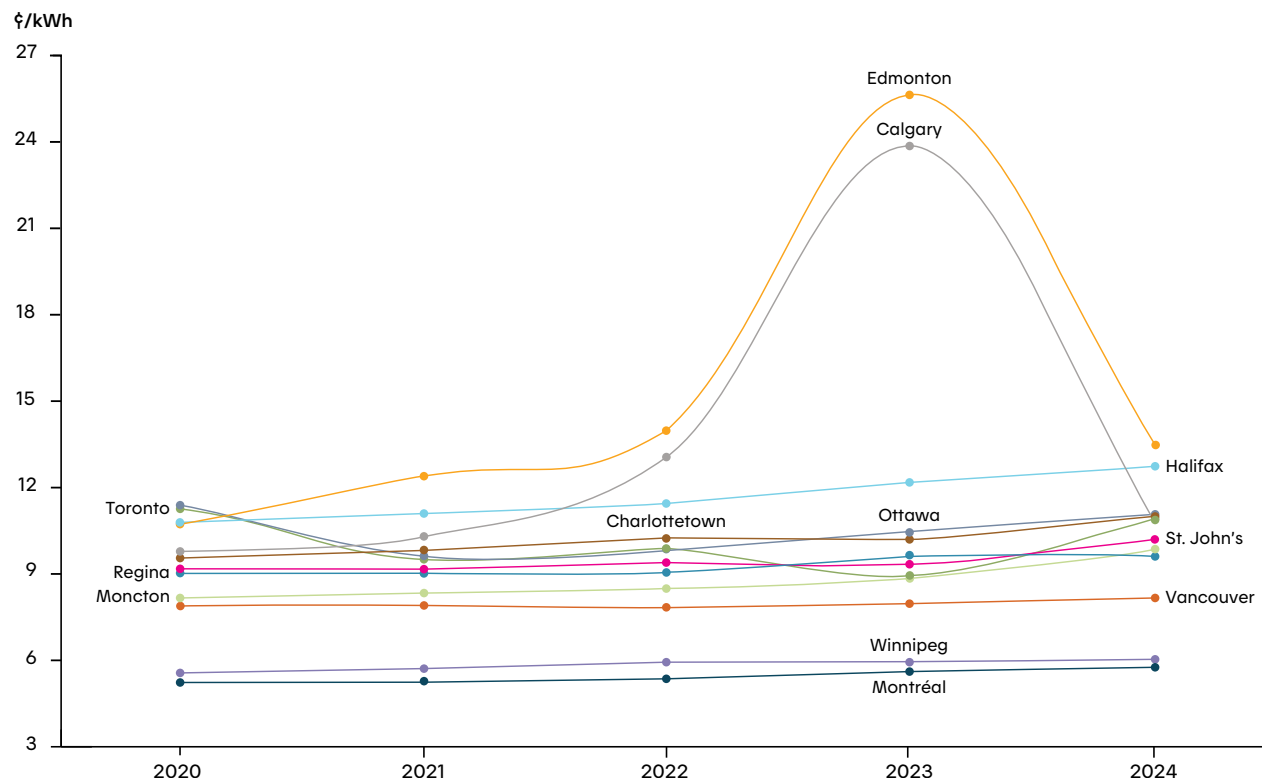
2) In Canadian currency.

3) Data compiled by Hydro-Québec in preparing the 2020–2024 editions of the *Comparison of Electricity Prices in Major North American Cities*.

4) Average prices excluding taxes.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2020–2024^{1, 2, 3, 4}



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh)^{1, 2, 3, 4}

	2020	2021	2022	2023	2024
Canadian Cities					
● Montréal, QC	5.20	5.24	5.33	5.55	5.74
● Calgary, AB	9.73	10.25	13.16	23.77	10.46
● Charlottetown, PE	9.51	9.77	10.17	10.17	10.99
● Edmonton, AB	10.64	12.35	14.08	25.62	13.17
● Halifax, NS	10.72	11.05	11.40	12.13	12.70
● Moncton, NB	8.13	8.28	8.44	8.81	9.80
● Ottawa, ON	11.36	9.57	9.78	10.39	11.05
● Regina, SK	8.98	8.98	8.98	9.57	9.57
● St. John's, NL	9.12	9.12	9.32	9.28	10.18
● Toronto, ON	11.23	9.45	9.76	8.88	10.90
● Vancouver, BC	7.84	7.88	7.76	7.91	8.12
● Winnipeg, MB	5.53	5.68	5.90	5.90	6.00

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW.

2) In Canadian currency.

3) Data compiled by Hydro-Québec in preparing the 2020–2024 editions of the *Comparison of Electricity Prices in Major North American Cities*.

4) Average prices excluding taxes.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based in part on a survey to which 14 utilities responded, and in part on estimates of bills calculated by Hydro-Québec.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on the rates in effect on April 1, 2024. The most recent rate adjustments applied by the Canadian utilities in the study between April 1, 2023, and April 1, 2024, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the detailed tables.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account, since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes apply different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where rates and taxes are applied uniformly except in territories located north of the 53rd parallel. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2024.

TIME-OF-USE RATES

The rates applied by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates. These utilities and the consumption levels to which time-of-use rates apply are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include clauses that allow them to adjust their customers' electricity bills according to different variables. Since these adjustments may be applied monthly or over a longer period, the bills issued by a given distributor may have varied between April 1, 2023, and April 1, 2024, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists the taxes applicable on April 1, 2024, by customer category; those which may be partially or fully refundable are indicated.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is \$0.7367 (C\$1 = US\$0.7367), the rate in effect at noon on April 1, 2024. The Canadian dollar had thus depreciated by 1.01% relative to the U.S. dollar on April 3, 2023.

HIGHLIGHTS

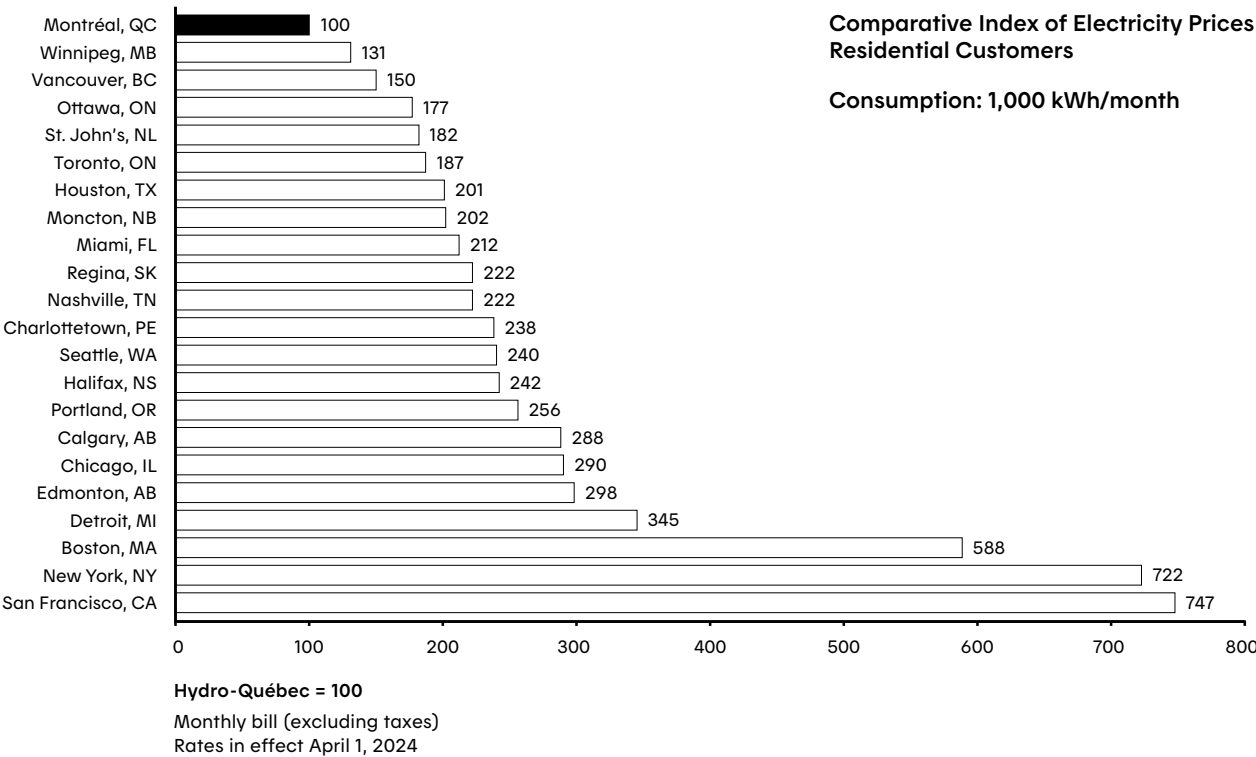
The document *Electricity Rates Effective April 1, 2024*, sets out Hydro-Québec’s rates established in accordance with Schedule 1 of the *Hydro-Québec Act*. Three types of rates are in effect: domestic rates, for residential and farm customers (hereinafter, “residential customers”); the industrial rate, for large-power industrial customers; and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study

have been analyzed according to these categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec’s residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kilowatthours (kWh), Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

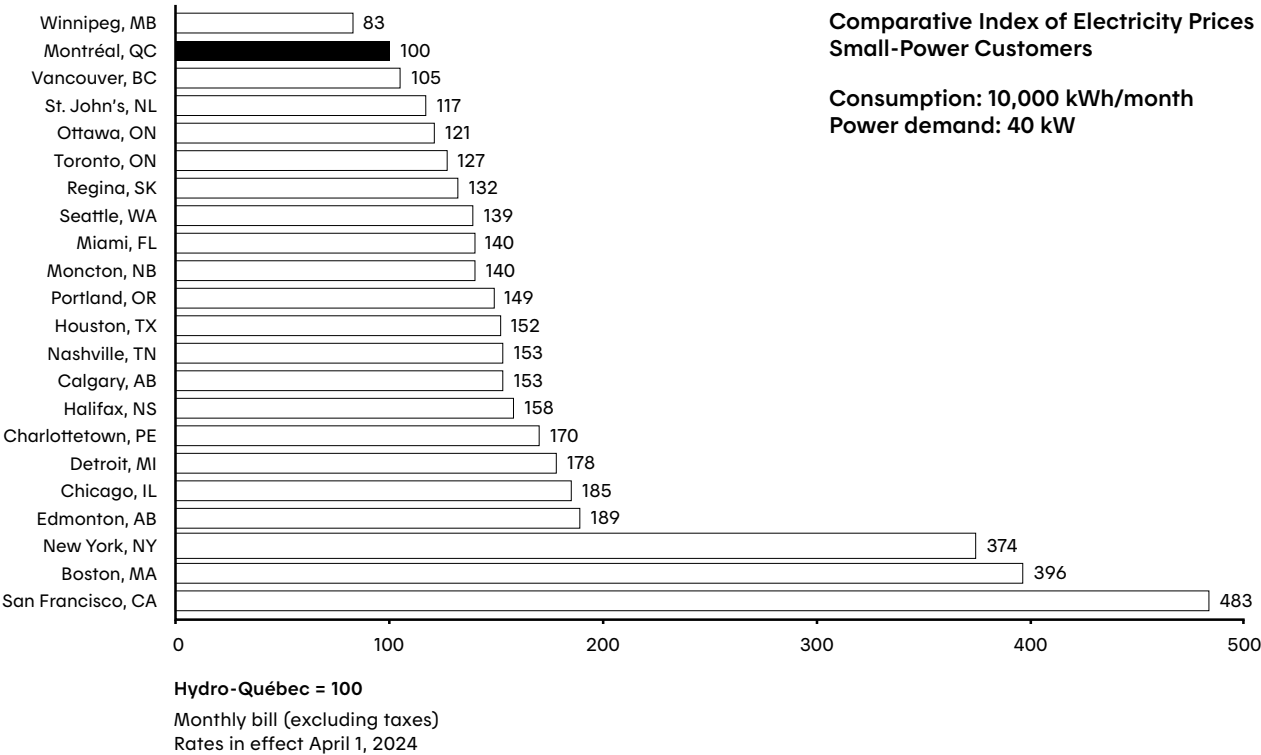
FIGURE 1



**SMALL-POWER CUSTOMERS
(LESS THAN 100 kW)**

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kilowatts (kW). Again this year, Montréal is in *second* place. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

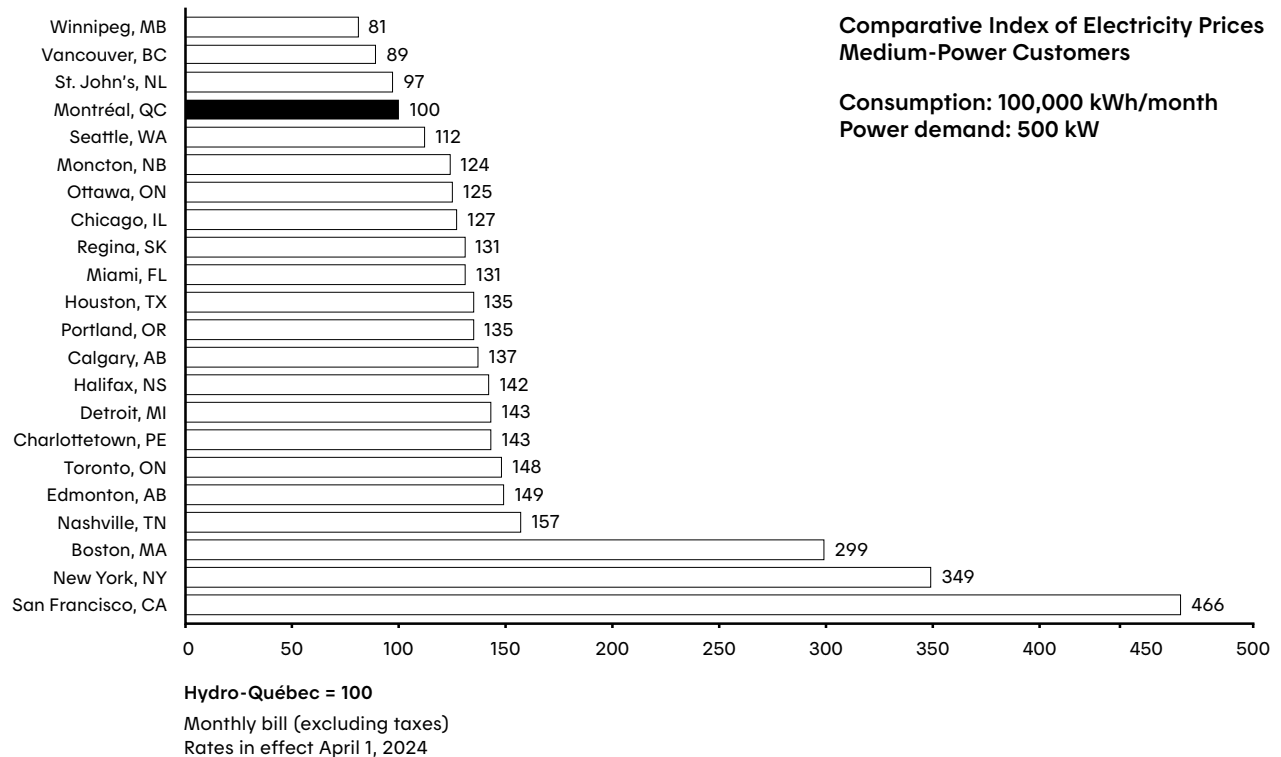


MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

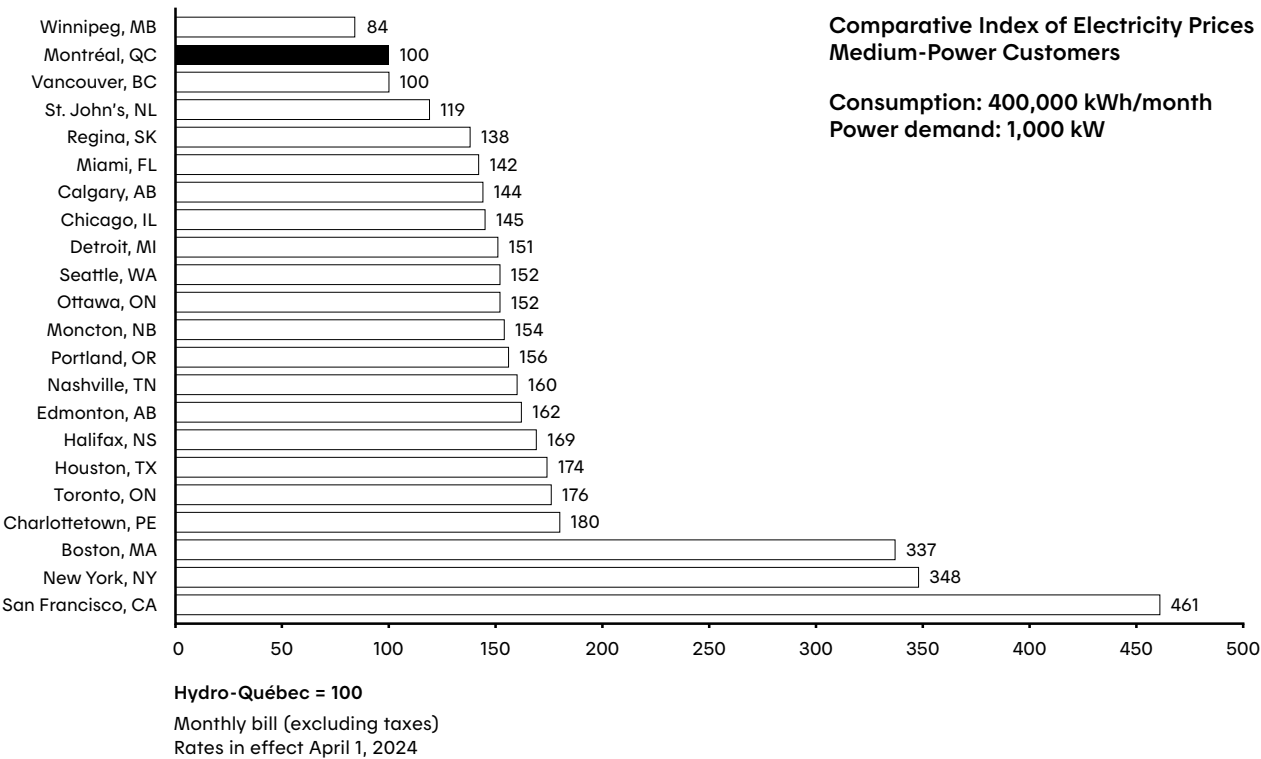
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal remains in *fourth* place.

FIGURE 3



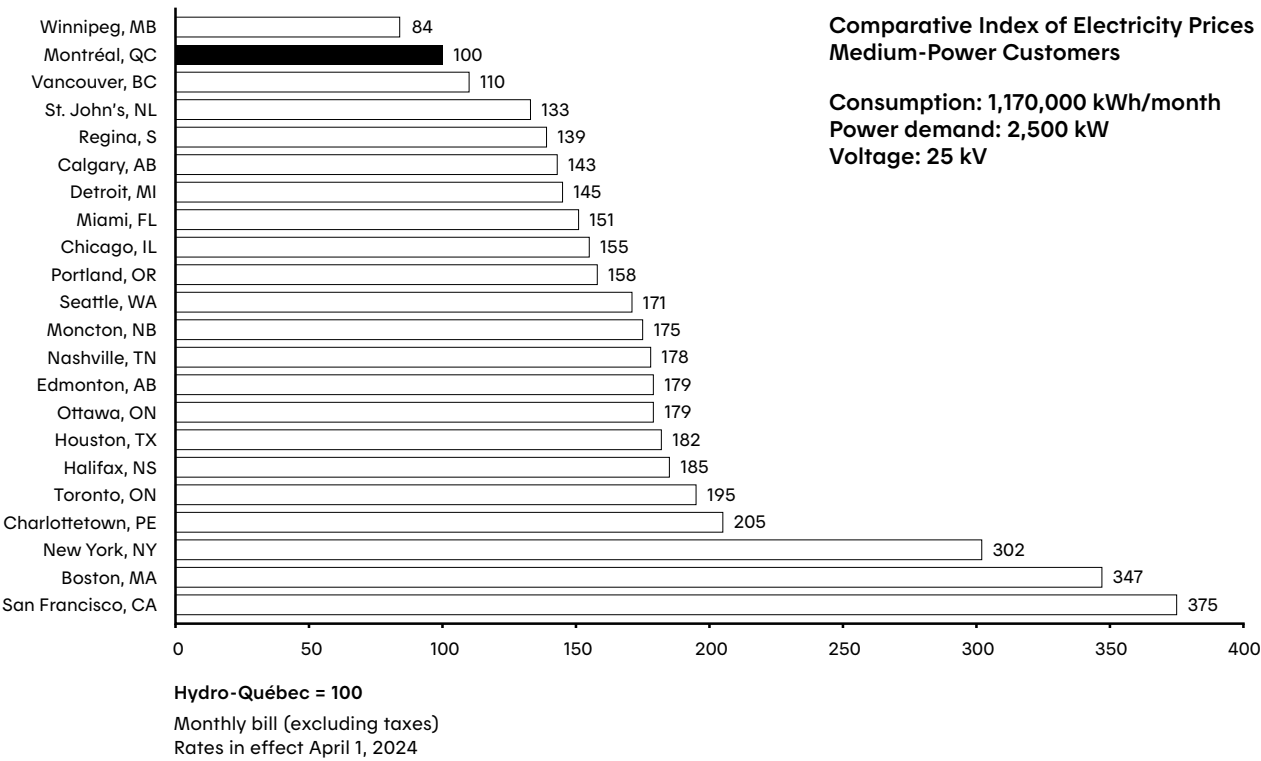
For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal ranks *second*.

FIGURE 4



In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal remains in *second* place.

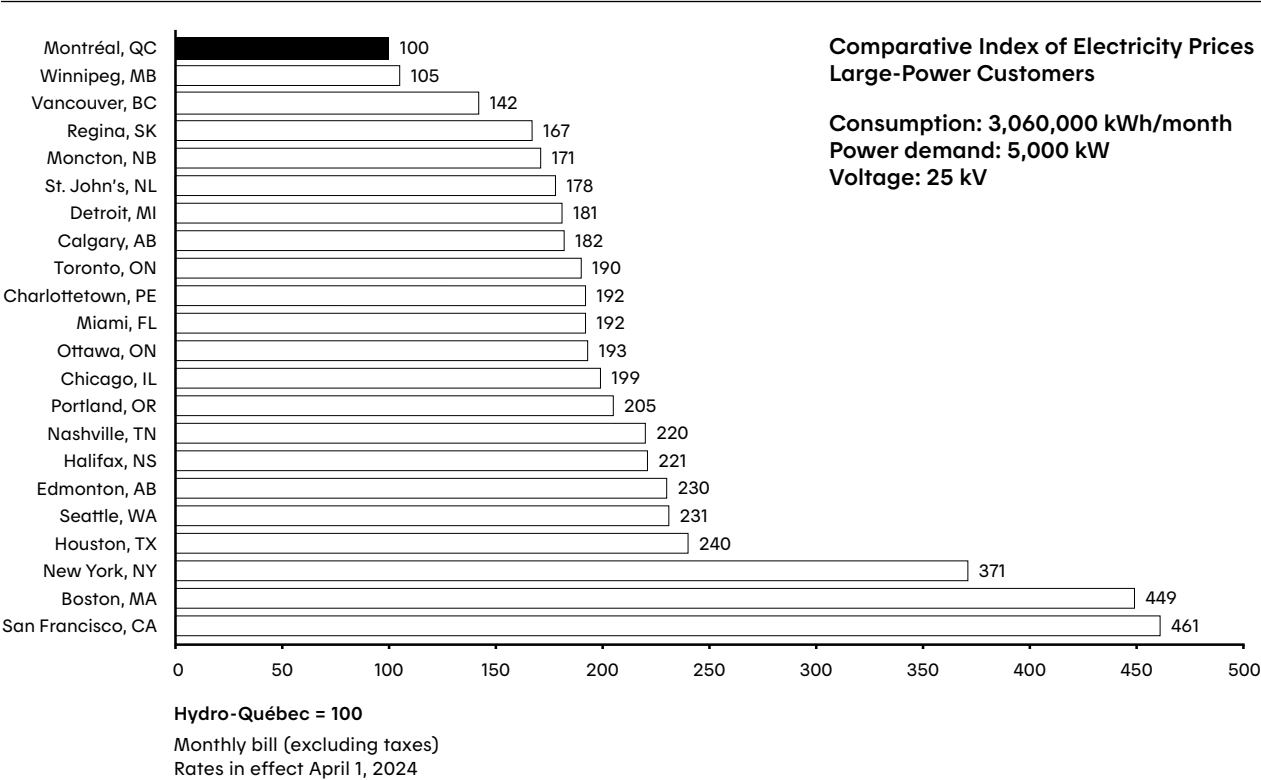
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

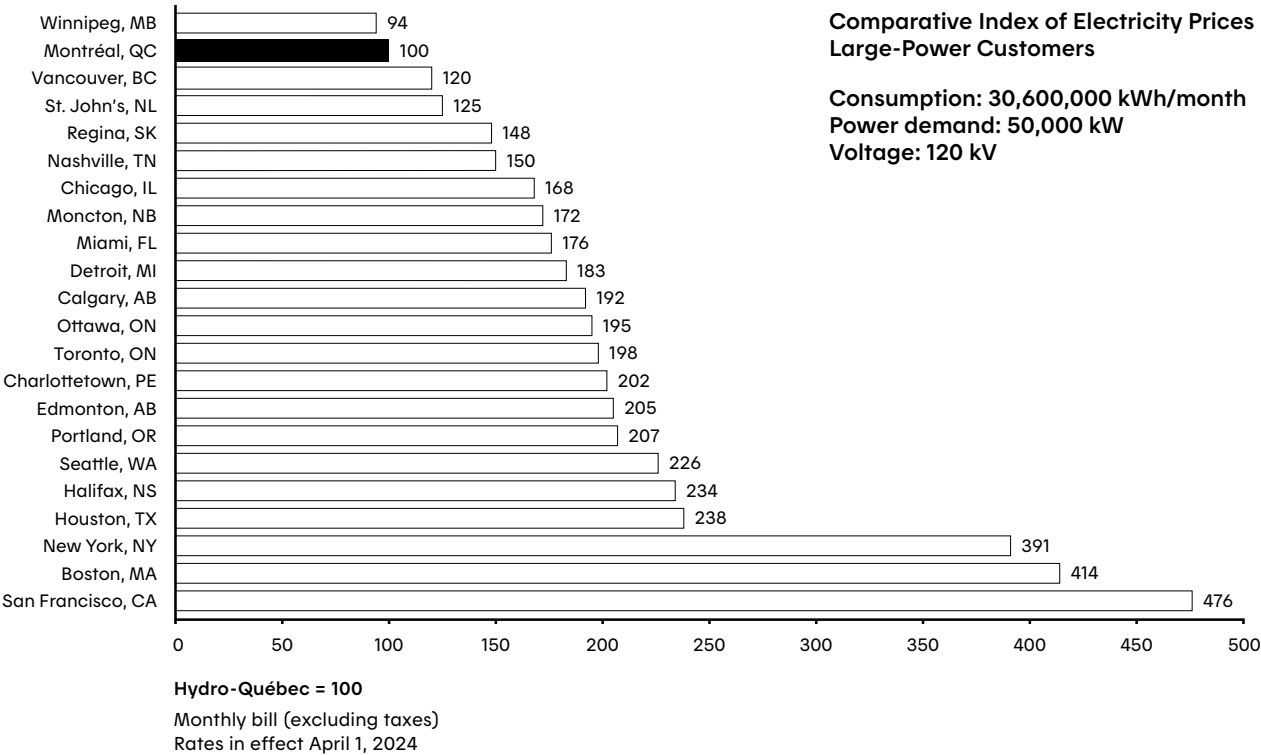
Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal ranks *first*.

FIGURE 6



For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal is in *second* place, coming in just behind Winnipeg.

FIGURE 7



01

Detailed Results

Summary Tables (excluding taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2024

(in C\$)

Summary Table (excluding taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ¹	5,000 kW ¹	50,000 kW ²
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	80.48	1,166.14	14,186.50	37,493.20	93,150.58	175,519.55	1,661,515.50
Calgary, AB	231.69	1,781.93	19,457.11	54,152.32	133,310.00	319,975.37	3,190,710.87
Charlottetown, PE ³	191.27	1,987.67	20,279.47	67,374.47	191,161.47	336,272.00	3,362,720.00
Edmonton, AB ⁴	239.84	2,209.09	21,151.08	60,817.73	166,364.81	402,960.75	3,400,335.12
Halifax, NS	194.64	1,843.12	20,146.00	63,436.00	172,777.65	388,567.66	3,885,701.83
Moncton, NB	162.97	1,636.87	17,590.27	57,655.27	163,238.27	299,911.44	2,860,940.00
Ottawa, ON	142.76	1,408.23	17,785.05	57,027.33	166,654.66	338,054.83	3,243,464.14
Regina, SK	178.94	1,542.78	18,549.00	51,770.10	129,917.75	292,824.48	2,461,848.10
St. John's, NL ⁵	146.20	1,361.81	13,805.49	44,714.59	124,292.10	311,593.05	2,073,232.00
Toronto, ON ³	150.55	1,485.58	21,019.96	65,867.11	181,221.19	333,520.49	3,291,629.55
Vancouver, BC	120.58	1,224.24	12,555.71	37,536.19	102,235.15	248,549.94	1,994,755.42
Winnipeg, MB	105.33	969.24	11,430.38	31,678.43	78,114.60	183,573.45	1,558,715.04
American Cities							
Boston, MA	473.12	4,619.10	42,401.10	126,411.95	323,425.66	787,621.85	6,878,081.54
Chicago, IL	233.74	2,162.95	18,043.83	54,190.18	144,008.74	349,470.77	2,791,624.00
Detroit, MI ³	277.88	2,071.65	20,223.81	56,761.31	135,407.99	317,442.42	3,038,242.70
Houston, TX ³	162.05	1,768.03	19,131.96	65,301.10	169,587.53	420,543.08	3,956,165.49
Miami, FL ³	170.42	1,635.68	18,553.85	53,113.26	140,956.80	336,705.83	2,916,853.92
Nashville, TN	178.94	1,778.37	22,260.61	59,909.46	166,204.14	385,639.57	2,495,753.90
New York, NY ³	581.38	4,361.86	49,519.46	130,576.38	280,990.80	650,927.26	6,503,148.71
Portland, OR ³	205.93	1,740.75	19,165.90	58,468.85	147,488.70	359,767.32	3,437,565.98
San Francisco, CA ³	601.51	5,627.67	66,168.40	172,809.55	349,125.61	808,741.25	7,906,577.30
Seattle, WA	193.06	1,622.64	15,950.94	56,847.83	159,418.41	406,282.70	3,748,748.72
AVERAGE	228.33	2,091.15	22,698.90	66,541.48	169,047.85	384,293.87	3,484,469.54

1) Supply voltage of 25 kV, customer-owned transformer.

2) Supply voltage of 120 kV, customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2024

(in ¢/kWh)¹

Summary Table (excluding taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ²	5,000 kW ²	50,000 kW ³
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	8.05	11.66	14.19	9.37	7.96	5.74	5.43
Calgary, AB	23.17	17.82	19.46	13.54	11.39	10.46	10.43
Charlottetown, PE ⁴	19.13	19.88	20.28	16.84	16.34	10.99	10.99
Edmonton, AB ⁵	23.98	22.09	21.15	15.20	14.22	13.17	11.11
Halifax, NS	19.46	18.43	20.15	15.86	14.77	12.70	12.70
Moncton, NB	16.30	16.37	17.59	14.41	13.95	9.80	9.35
Ottawa, ON	14.28	14.08	17.79	14.26	14.24	11.05	10.60
Regina, SK	17.89	15.43	18.55	12.94	11.10	9.57	8.05
St. John's, NL ⁶	14.62	13.62	13.81	11.18	10.62	10.18	6.78
Toronto, ON ⁴	15.06	14.86	21.02	16.47	15.49	10.90	10.76
Vancouver, BC	12.06	12.24	12.56	9.38	8.74	8.12	6.52
Winnipeg, MB	10.53	9.69	11.43	7.92	6.68	6.00	5.09
American Cities							
Boston, MA	47.31	46.19	42.40	31.60	27.64	25.74	22.48
Chicago, IL	23.37	21.63	18.04	13.55	12.31	11.42	9.12
Detroit, MI ⁴	27.79	20.72	20.22	14.19	11.57	10.37	9.93
Houston, TX ⁴	16.20	17.68	19.13	16.33	14.49	13.74	12.93
Miami, FL ⁴	17.04	16.36	18.55	13.28	12.05	11.00	9.53
Nashville, TN	17.89	17.78	22.26	14.98	14.21	12.60	8.16
New York, NY ⁴	58.14	43.62	49.52	32.64	24.02	21.27	21.25
Portland, OR ⁴	20.59	17.41	19.17	14.62	12.61	11.76	11.23
San Francisco, CA ⁴	60.15	56.28	66.17	43.20	29.84	26.43	25.84
Seattle, WA	19.31	16.23	15.95	14.21	13.63	13.28	12.25
AVERAGE	22.83	20.91	22.70	16.64	14.45	12.56	11.39

1) In Canadian currency.

2) Supply voltage of 25 kV, customer-owned transformer.

3) Supply voltage of 120 kV, customer-owned transformer.

4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2024

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ¹	5,000 kW ¹	50,000 kW ²
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	288	153	137	144	143	182	192
Charlottetown, PE ³	238	170	143	180	205	192	202
Edmonton, AB ⁴	298	189	149	162	179	230	205
Halifax, NS	242	158	142	169	185	221	234
Moncton, NB	202	140	124	154	175	171	172
Ottawa, ON	177	121	125	152	179	193	195
Regina, SK	222	132	131	138	139	167	148
St. John's, NL ⁵	182	117	97	119	133	178	125
Toronto, ON ³	187	127	148	176	195	190	198
Vancouver, BC	150	105	89	100	110	142	120
Winnipeg, MB	131	83	81	84	84	105	94
American Cities							
Boston, MA	588	396	299	337	347	449	414
Chicago, IL	290	185	127	145	155	199	168
Detroit, MI ³	345	178	143	151	145	181	183
Houston, TX ³	201	152	135	174	182	240	238
Miami, FL ³	212	140	131	142	151	192	176
Nashville, TN	222	153	157	160	178	220	150
New York, NY ³	722	374	349	348	302	371	391
Portland, OR ³	256	149	135	156	158	205	207
San Francisco, CA ³	747	483	466	461	375	461	476
Seattle, WA	240	139	112	152	171	231	226
AVERAGE	284	179	160	177	181	219	210

1) Supply voltage of 25 kV, customer-owned transformer.

2) Supply voltage of 120 kV, customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Results

Summary Tables (including taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2024

(in C\$)

Summary Table (including taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ¹	5,000 kW ¹	50,000 kW ²
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	92.53	1,340.77	16,310.93	43,107.81	107,099.88	201,803.61	1,910,327.45
Calgary, AB	243.27	1,871.02	20,429.97	56,859.93	139,975.50	335,974.14	3,350,246.41
Charlottetown, PE ³	219.96	2,285.82	23,321.39	77,480.64	219,835.69	386,712.80	3,867,128.00
Edmonton, AB ⁴	251.83	2,319.54	22,208.64	63,858.62	174,683.05	423,108.79	3,729,248.28
Halifax, NS	204.37	2,119.59	23,167.90	72,951.40	198,694.30	446,852.81	4,468,557.10
Moncton, NB	187.42	1,882.40	20,228.81	66,303.56	187,724.01	344,898.16	3,290,081.00
Ottawa, ON	165.76	1,635.08	20,097.11	64,440.88	188,319.77	382,001.95	3,665,114.48
Regina, SK	217.05	1,988.44	23,679.82	67,449.38	170,359.58	388,451.97	3,317,381.30
St. John's, NL ⁵	168.13	1,566.08	15,876.31	51,421.78	142,935.92	358,332.01	2,384,216.80
Toronto, ON ³	174.80	1,724.89	23,752.55	74,429.83	204,779.94	376,878.15	3,719,541.39
Vancouver, BC	128.60	1,285.45	13,183.49	39,412.99	107,346.91	260,977.43	2,094,493.20
Winnipeg, MB	120.73	1,136.44	13,402.13	37,142.96	87,214.95	204,959.76	1,740,305.34
American Cities							
Boston, MA	473.12	4,899.73	44,970.50	133,989.97	342,695.80	834,379.39	7,283,273.42
Chicago, IL	246.75	2,268.34	19,003.57	57,829.43	154,242.23	375,079.26	3,014,162.99
Detroit, MI ³	302.89	2,299.53	22,448.43	63,005.05	150,302.87	352,361.09	3,372,449.39
Houston, TX ³	163.67	1,910.09	20,654.65	70,564.05	183,478.16	455,037.22	4,280,541.42
Miami, FL ³	198.85	2,043.21	23,232.88	66,034.47	174,839.49	416,548.17	3,570,409.08
Nashville, TN	178.94	1,902.86	23,818.86	64,103.12	177,838.43	412,634.34	2,670,456.67
New York, NY ³	630.99	4,858.05	55,151.79	145,441.59	313,015.77	725,133.64	7,244,520.93
Portland, OR ³	208.73	1,764.48	19,430.50	59,272.94	149,629.38	365,003.29	3,487,680.20
San Francisco, CA ³	601.92	5,913.13	69,517.54	181,612.92	367,058.33	850,424.41	8,314,367.10
Seattle, WA	193.06	1,622.64	15,950.94	56,847.83	159,418.41	406,282.70	3,748,748.72
AVERAGE	244.24	2,301.71	24,992.67	73,343.69	186,431.29	422,901.59	3,841,965.94

1) Supply voltage of 25 kV, customer-owned transformer.

2) Supply voltage of 120 kV, customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2024

(in ¢/kWh)¹

Summary Table (including taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ²	5,000 kW ²	50,000 kW ³
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	9.25	13.41	16.31	10.78	9.15	6.59	6.24
Calgary, AB	24.33	18.71	20.43	14.21	11.96	10.98	10.95
Charlottetown, PE ⁴	22.00	22.86	23.32	19.37	18.79	12.64	12.64
Edmonton, AB ⁵	25.18	23.20	22.21	15.96	14.93	13.83	12.19
Halifax, NS	20.44	21.20	23.17	18.24	16.98	14.60	14.60
Moncton, NB	18.74	18.82	20.23	16.58	16.04	11.27	10.75
Ottawa, ON	16.58	16.35	20.10	16.11	16.10	12.48	11.98
Regina, SK	21.71	19.88	23.68	16.86	14.56	12.69	10.84
St. John's, NL ⁶	16.81	15.66	15.88	12.86	12.22	11.71	7.79
Toronto, ON ⁴	17.48	17.25	23.75	18.61	17.50	12.32	12.16
Vancouver, BC	12.86	12.85	13.18	9.85	9.17	8.53	6.84
Winnipeg, MB	12.07	11.36	13.40	9.29	7.45	6.70	5.69
American Cities							
Boston, MA	47.31	49.00	44.97	33.50	29.29	27.27	23.80
Chicago, IL	24.67	22.68	19.00	14.46	13.18	12.26	9.85
Detroit, MI ⁴	30.29	23.00	22.45	15.75	12.85	11.52	11.02
Houston, TX ⁴	16.37	19.10	20.65	17.64	15.68	14.87	13.99
Miami, FL ⁴	19.88	20.43	23.23	16.51	14.94	13.61	11.67
Nashville, TN	17.89	19.03	23.82	16.03	15.20	13.48	8.73
New York, NY ⁴	63.10	48.58	55.15	36.36	26.75	23.70	23.67
Portland, OR ⁴	20.87	17.64	19.43	14.82	12.79	11.93	11.40
San Francisco, CA ⁴	60.19	59.13	69.52	45.40	31.37	27.79	27.17
Seattle, WA	19.31	16.23	15.95	14.21	13.63	13.28	12.25
AVERAGE	24.42	23.02	24.99	18.34	15.93	13.82	12.56

1) In Canadian currency.

2) Supply voltage of 25 kV, customer-owned transformer.

3) Supply voltage of 120 kV, customer-owned transformer.

4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2024

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential Customers	Small- Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW ¹	5,000 kW ¹	50,000 kW ²
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	263	140	125	132	131	166	175
Charlottetown, PE ³	238	170	143	180	205	192	202
Edmonton, AB ⁴	272	173	136	148	163	210	195
Halifax, NS	221	158	142	169	186	221	234
Moncton, NB	203	140	124	154	175	171	172
Ottawa, ON	179	122	123	149	176	189	192
Regina, SK	235	148	145	156	159	192	174
St. John's, NL ⁵	182	117	97	119	133	178	125
Toronto, ON ³	189	129	146	173	191	187	195
Vancouver, BC	139	96	81	91	100	129	110
Winnipeg, MB	130	85	82	86	81	102	91
American Cities							
Boston, MA	511	365	276	311	320	413	381
Chicago, IL	267	169	117	134	144	186	158
Detroit, MI ³	327	172	138	146	140	175	177
Houston, TX ³	177	142	127	164	171	225	224
Miami, FL ³	215	152	142	153	163	206	187
Nashville, TN	193	142	146	149	166	204	140
New York, NY ³	682	362	338	337	292	359	379
Portland, OR ³	226	132	119	137	140	181	183
San Francisco, CA ³	651	441	426	421	343	421	435
Seattle, WA	209	121	98	132	149	201	196
AVERAGE	264	172	153	170	174	210	201

1) Supply voltage of 25 kV, customer-owned transformer.

2) Supply voltage of 120 kV, customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Results

Residential Customers

Monthly Bills

Average Prices

Comparative Index

RESIDENTIAL CUSTOMERS

Monthly Bills on April 1, 2024
(in C\$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	55.34	63.72	80.48	176.63	280.05
Calgary, AB	158.01	182.57	231.69	428.14	624.60
Charlottetown, PE ¹	128.76	149.60	191.27	357.97	491.17
Edmonton, AB	160.47	186.92	239.84	451.51	663.18
Halifax, NS	128.84	150.77	194.64	370.11	545.58
Moncton, NB	112.46	129.30	162.97	297.67	432.37
Ottawa, ON	99.79	114.12	142.76	257.40	366.73
Regina, SK	123.08	141.70	178.94	327.89	476.84
St. John's, NL ²	97.25	113.57	146.20	276.75	407.31
Toronto, ON ¹	107.21	121.66	150.55	266.12	381.69
Vancouver, BC	71.80	87.07	120.58	254.62	388.66
Winnipeg, MB	69.38	81.36	105.33	201.20	297.07
American Cities					
Boston, MA	300.80	358.26	473.12	932.67	1,392.22
Chicago, IL	154.60	180.99	233.74	444.89	656.03
Detroit, MI ¹	177.16	210.73	277.88	546.47	815.07
Houston, TX ¹	117.02	136.53	162.05	318.14	474.23
Miami, FL ¹	111.37	131.06	170.42	355.01	539.61
Nashville, TN	124.01	142.32	178.94	325.41	482.75
New York, NY ¹	372.73	442.28	581.38	1,137.80	1,694.22
Portland, OR ¹	134.74	158.47	205.93	395.77	597.50
San Francisco, CA ¹	346.45	437.07	601.51	1,326.44	2,051.37
Seattle, WA	123.22	146.50	193.06	379.30	565.53
AVERAGE	148.84	175.75	228.33	446.72	664.72

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

2) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Average Prices on April 1, 2024

(in ¢/kWh)¹

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	8.85	8.50	8.05	8.83	9.34
Calgary, AB	25.28	24.34	23.17	21.41	20.82
Charlottetown, PE ²	20.60	19.95	19.13	17.90	16.37
Edmonton, AB	25.68	24.92	23.98	22.58	22.11
Halifax, NS	20.61	20.10	19.46	18.51	18.19
Moncton, NB	17.99	17.24	16.30	14.88	14.41
Ottawa, ON	15.97	15.22	14.28	12.87	12.22
Regina, SK	19.69	18.89	17.89	16.39	15.89
St. John's, NL ³	15.56	15.14	14.62	13.84	13.58
Toronto, ON ²	17.15	16.22	15.06	13.31	12.72
Vancouver, BC	11.49	11.61	12.06	12.73	12.96
Winnipeg, MB	11.10	10.85	10.53	10.06	9.90
American Cities					
Boston, MA	48.13	47.77	47.31	46.63	46.41
Chicago, IL	24.74	24.13	23.37	22.24	21.87
Detroit, MI ²	28.34	28.10	27.79	27.32	27.17
Houston, TX ²	18.72	18.20	16.20	15.91	15.81
Miami, FL ²	17.82	17.47	17.04	17.75	17.99
Nashville, TN	19.84	18.98	17.89	16.27	16.09
New York, NY ²	59.64	58.97	58.14	56.89	56.47
Portland, OR ²	21.56	21.13	20.59	19.79	19.92
San Francisco, CA ²	55.43	58.28	60.15	66.32	68.38
Seattle, WA	19.72	19.53	19.31	18.96	18.85
AVERAGE	23.81	23.43	22.83	22.34	22.16

1) In Canadian currency.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Comparative Index on April 1, 2024
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	286	287	288	242	223
Charlottetown, PE ¹	233	235	238	203	175
Edmonton, AB	290	293	298	256	237
Halifax, NS	233	237	242	210	195
Moncton, NB	203	203	202	169	154
Ottawa, ON	180	179	177	146	131
Regina, SK	222	222	222	186	170
St. John's, NL ²	176	178	182	157	145
Toronto, ON ¹	194	191	187	151	136
Vancouver, BC	130	137	150	144	139
Winnipeg, MB	125	128	131	114	106
American Cities					
Boston, MA	544	562	588	528	497
Chicago, IL	279	284	290	252	234
Detroit, MI ¹	320	331	345	309	291
Houston, TX ¹	211	214	201	180	169
Miami, FL ¹	201	206	212	201	193
Nashville, TN	224	223	222	184	172
New York, NY ¹	674	694	722	644	605
Portland, OR ¹	243	249	256	224	213
San Francisco, CA ¹	626	686	747	751	733
Seattle, WA	223	230	240	215	202
AVERAGE	269	276	284	253	237

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

2) Newfoundland Power rates.

04

Detailed Results **Small-Power Customers**

Monthly Bills

Average Prices

Comparative Index

SMALL-POWER CUSTOMERS

Monthly Bills on April 1, 2024
(in C\$)

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	100.73	244.70	1,166.14	2,133.74	3,158.95
Calgary, AB	199.67	420.38	1,781.93	3,048.48	3,969.54
Charlottetown, PE ¹	177.80	433.17	1,987.67	3,331.87	4,812.47
Edmonton, AB	190.56	463.34	2,209.09	4,124.73	5,751.73
Halifax, NS	149.37	357.11	1,843.12	3,137.06	4,607.80
Moncton, NB	146.60	344.97	1,636.87	2,847.87	4,084.27
Ottawa, ON	123.42	297.02	1,408.23	2,477.14	4,258.65
Regina, SK	153.80	341.50	1,542.78	2,955.12	3,867.60
St. John's, NL ²	118.75	311.88	1,361.81	2,320.81	3,388.78
Toronto, ON ¹	144.43	325.67	1,485.58	2,833.77	4,862.27
Vancouver, BC	107.92	268.80	1,224.24	1,954.80	3,048.08
Winnipeg, MB	91.88	210.44	969.24	2,034.53	2,691.68
American Cities					
Boston, MA	327.85	845.77	4,619.10	8,850.33	12,255.29
Chicago, IL	242.46	556.12	2,162.95	3,713.69	5,354.63
Detroit, MI ¹	169.14	458.13	2,071.65	2,878.41	5,097.01
Houston, TX ¹	130.82	452.47	1,768.03	3,115.25	4,398.88
Miami, FL ¹	138.91	341.52	1,635.68	3,051.18	4,027.69
Nashville, TN	204.13	441.55	1,778.37	4,152.63	5,080.34
New York, NY ¹	400.96	1,348.80	4,361.86	9,028.09	10,767.67
Portland, OR ¹	171.83	418.37	1,740.75	2,848.18	4,302.29
San Francisco, CA ¹	460.05	1,204.50	5,627.67	8,991.93	13,345.41
Seattle, WA	139.78	340.16	1,622.64	2,504.27	3,873.48
AVERAGE	185.95	473.93	2,091.15	3,742.45	5,318.39

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

2) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Average Prices on April 1, 2024

(in ¢/kWh)¹

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	13.43	12.24	11.66	15.24	12.64
Calgary, AB	26.62	21.02	17.82	21.77	15.88
Charlottetown, PE ²	23.71	21.66	19.88	23.80	19.25
Edmonton, AB	25.41	23.17	22.09	29.46	23.01
Halifax, NS	19.92	17.86	18.43	22.41	18.43
Moncton, NB	19.55	17.25	16.37	20.34	16.34
Ottawa, ON	16.46	14.85	14.08	17.69	17.03
Regina, SK	20.51	17.08	15.43	21.11	15.47
St. John's, NL ³	15.83	15.59	13.62	16.58	13.56
Toronto, ON ²	19.26	16.28	14.86	20.24	19.45
Vancouver, BC	14.39	13.44	12.24	13.96	12.19
Winnipeg, MB	12.25	10.52	9.69	14.53	10.77
American Cities					
Boston, MA	43.71	42.29	46.19	63.22	49.02
Chicago, IL	32.33	27.81	21.63	26.53	21.42
Detroit, MI ²	22.55	22.91	20.72	20.56	20.39
Houston, TX ²	17.44	22.62	17.68	22.25	17.60
Miami, FL ²	18.52	17.08	16.36	21.79	16.11
Nashville, TN	27.22	22.08	17.78	29.66	20.32
New York, NY ²	53.46	67.44	43.62	64.49	43.07
Portland, OR ²	22.91	20.92	17.41	20.34	17.21
San Francisco, CA ²	61.34	60.23	56.28	64.23	53.38
Seattle, WA	18.64	17.01	16.23	17.89	15.49
AVERAGE	24.79	23.70	20.91	26.73	21.27

1) In Canadian currency.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Comparative Index on April 1, 2024
(Hydro-Québec = 100)

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	198	172	153	143	126
Charlottetown, PE ¹	177	177	170	156	152
Edmonton, AB	189	189	189	193	182
Halifax, NS	148	146	158	147	146
Moncton, NB	146	141	140	133	129
Ottawa, ON	123	121	121	116	135
Regina, SK	153	140	132	138	122
St. John's, NL ²	118	127	117	109	107
Toronto, ON ¹	143	133	127	133	154
Vancouver, BC	107	110	105	92	96
Winnipeg, MB	91	86	83	95	85
American Cities					
Boston, MA	325	346	396	415	388
Chicago, IL	241	227	185	174	170
Detroit, MI ¹	168	187	178	135	161
Houston, TX ¹	130	185	152	146	139
Miami, FL ¹	138	140	140	143	128
Nashville, TN	203	180	153	195	161
New York, NY ¹	398	551	374	423	341
Portland, OR ¹	171	171	149	133	136
San Francisco, CA ¹	457	492	483	421	422
Seattle, WA	139	139	139	117	123
AVERAGE	185	194	179	175	168

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

2) Newfoundland Power rates.

05

Detailed Results

Medium-Power Customers

Monthly Bills

Average Prices

Comparative Index

MEDIUM-POWER CUSTOMERS

Monthly Bills on April 1, 2024

(in C\$)

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW ¹
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	14,186.50	20,183.00	28,373.00	37,493.20	93,150.58
Calgary, AB	19,457.11	27,522.39	38,021.75	54,152.32	133,310.00
Charlottetown, PE ²	20,279.47	33,739.47	40,454.47	67,374.47	191,161.47
Edmonton, AB ³	21,151.08	31,499.45	40,121.00	60,817.73	166,364.81
Halifax, NS	20,146.00	31,718.00	40,292.00	63,436.00	172,777.65
Moncton, NB	17,590.27	28,830.27	35,175.27	57,655.27	163,238.27
Ottawa, ON	17,785.05	28,613.79	35,369.85	57,027.33	166,654.66
Regina, SK	18,549.00	25,771.00	37,326.10	51,770.10	129,917.75
St. John's, NL ⁴	13,805.49	23,049.72	26,383.74	44,714.59	124,292.10
Toronto, ON ²	21,019.96	33,299.83	41,552.95	65,867.11	181,221.19
Vancouver, BC	12,555.71	18,772.27	25,103.07	37,536.19	102,235.15
Winnipeg, MB	11,430.38	15,976.38	22,586.43	31,678.43	78,114.60
American Cities					
Boston, MA	42,401.10	63,314.57	84,585.02	126,411.95	323,425.66
Chicago, IL	18,043.83	27,201.61	35,874.64	54,190.18	144,008.74
Detroit, MI ²	20,223.81	28,547.45	40,392.87	56,761.31	135,407.99
Houston, TX ²	19,131.96	30,801.29	41,962.42	65,301.10	169,587.53
Miami, FL ²	18,553.85	26,616.81	36,987.34	53,113.26	140,956.80
Nashville, TN	22,260.61	30,102.31	44,226.06	59,909.46	166,204.14
New York, NY ²	49,519.46	65,333.85	98,947.60	130,576.38	280,990.80
Portland, OR ²	19,165.90	29,102.17	36,922.33	58,468.85	147,488.70
San Francisco, CA ²	66,168.40	87,937.47	131,304.50	172,809.55	349,125.61
Seattle, WA	15,950.94	28,398.30	32,213.64	56,847.83	159,418.41
AVERAGE	22,698.90	33,469.61	45,189.82	66,541.48	169,047.85

1) Supply voltage of 25 kV, customer-owned transformer.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

4) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Average Prices on April 1, 2024

(in ¢/kWh)¹

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW ²
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	14.19	10.09	14.19	9.37	7.96
Calgary, AB	19.46	13.76	19.01	13.54	11.39
Charlottetown, PE ³	20.28	16.87	20.23	16.84	16.34
Edmonton, AB ⁴	21.15	15.75	20.06	15.20	14.22
Halifax, NS	20.15	15.86	20.15	15.86	14.77
Moncton, NB	17.59	14.42	17.59	14.41	13.95
Ottawa, ON	17.79	14.31	17.68	14.26	14.24
Regina, SK	18.55	12.89	18.66	12.94	11.10
St. John's, NL ⁵	13.81	11.52	13.19	11.18	10.62
Toronto, ON ³	21.02	16.65	20.78	16.47	15.49
Vancouver, BC	12.56	9.39	12.55	9.38	8.74
Winnipeg, MB	11.43	7.99	11.29	7.92	6.68
American Cities					
Boston, MA	42.40	31.66	42.29	31.60	27.64
Chicago, IL	18.04	13.60	17.94	13.55	12.31
Detroit, MI ³	20.22	14.27	20.20	14.19	11.57
Houston, TX ³	19.13	15.40	20.98	16.33	14.49
Miami, FL ³	18.55	13.31	18.49	13.28	12.05
Nashville, TN	22.26	15.05	22.11	14.98	14.21
New York, NY ³	49.52	32.67	49.47	32.64	24.02
Portland, OR ³	19.17	14.55	18.46	14.62	12.61
San Francisco, CA ³	66.17	43.97	65.65	43.20	29.84
Seattle, WA	15.95	14.20	16.11	14.21	13.63
AVERAGE	22.70	16.73	22.59	16.64	14.45

1) In Canadian currency.

2) Supply voltage of 25 kV, customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Comparative Index on April 1, 2024
(Hydro-Québec = 100)

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW ¹
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	137	136	134	144	143
Charlottetown, PE ²	143	167	143	180	205
Edmonton, AB ³	149	156	141	162	179
Halifax, NS	142	157	142	169	185
Moncton, NB	124	143	124	154	175
Ottawa, ON	125	142	125	152	179
Regina, SK	131	128	132	138	139
St. John's, NL ⁴	97	114	93	119	133
Toronto, ON ²	148	165	146	176	195
Vancouver, BC	89	93	88	100	110
Winnipeg, MB	81	79	80	84	84
American Cities					
Boston, MA	299	314	298	337	347
Chicago, IL	127	135	126	145	155
Detroit, MI ²	143	141	142	151	145
Houston, TX ²	135	153	148	174	182
Miami, FL ²	131	132	130	142	151
Nashville, TN	157	149	156	160	178
New York, NY ²	349	324	349	348	302
Portland, OR ²	135	144	130	156	158
San Francisco, CA ²	466	436	463	461	375
Seattle, WA	112	141	114	152	171
AVERAGE	160	166	159	177	181

1) Supply voltage of 25 kV, customer-owned transformer.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

4) Newfoundland Power rates.

06

Detailed Results **Large-Power Customers**

Monthly Bills

Average Prices

Comparative Index

LARGE-POWER CUSTOMERS

Monthly Bills on April 1, 2024

(in C\$)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage ¹	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%

Canadian Cities

Montréal, QC	149,462.75	175,519.55	319,274.70	966,509.70	1,400,947.50	1,661,515.50
Calgary, AB	261,653.90	319,975.37	609,782.25	1,846,785.21	2,607,496.17	3,190,710.87
Charlottetown, PE ²	274,208.00	336,272.00	641,512.00	1,945,224.00	2,742,080.00	3,362,720.00
Edmonton, AB ³	326,300.84	402,960.75	655,743.94	1,972,834.03	2,768,606.08	3,400,335.12
Halifax, NS	312,744.46	388,567.66	739,223.73	2,242,958.18	3,127,469.83	3,885,701.83
Moncton, NB	252,482.52	299,911.44	548,824.00	1,662,048.00	2,393,660.00	2,860,940.00
Ottawa, ON	280,247.91	338,054.83	631,974.62	1,884,729.71	2,665,394.95	3,243,464.14
Regina, SK	247,802.88	292,824.48	477,397.99	1,429,858.04	2,028,048.10	2,461,848.10
St. John's, NL ⁴	245,601.99	311,593.05	584,096.75	1,201,754.40	1,711,648.00	2,073,232.00
Toronto, ON ²	309,187.42	333,520.49	650,030.67	1,948,524.80	3,048,298.88	3,291,629.55
Vancouver, BC	204,462.09	248,549.94	381,465.07	1,156,059.64	1,645,112.48	1,994,755.42
Winnipeg, MB	153,196.65	183,573.45	298,182.32	903,593.08	1,287,563.04	1,558,715.04

American Cities

Boston, MA	646,349.09	787,621.85	1,305,381.72	3,962,231.60	5,465,353.92	6,878,081.54
Chicago, IL	286,828.35	349,470.77	528,572.20	1,602,392.13	2,165,199.79	2,791,624.00
Detroit, MI ²	270,068.40	317,442.42	584,930.98	1,768,841.53	2,571,930.19	3,038,242.70
Houston, TX ²	335,678.46	420,543.08	750,578.76	2,276,836.48	3,121,231.21	3,956,165.49
Miami, FL ²	281,564.98	336,705.83	560,992.83	1,693,394.55	2,420,175.83	2,916,853.92
Nashville, TN	328,202.00	385,639.57	497,046.23	1,464,056.51	2,198,567.18	2,495,753.90
New York, NY ²	561,301.16	650,927.26	1,256,361.04	3,797,597.61	5,606,887.62	6,503,148.71
Portland, OR ²	289,724.54	359,767.32	656,327.69	1,985,100.28	2,762,876.31	3,437,565.98
San Francisco, CA ²	677,364.33	808,741.25	1,531,701.24	4,598,710.43	6,592,808.13	7,906,577.30
Seattle, WA	318,066.98	406,282.70	714,022.87	2,158,042.34	2,938,768.40	3,748,748.72
AVERAGE	318,749.99	384,293.87	678,337.44	2,021,276.47	2,875,914.71	3,484,469.54

1) Customer-owned transformer.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Average Prices on April 1, 2024

(in ¢/kWh)¹

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage ²	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%

Canadian Cities

Montréal, QC	6.39	5.74	5.54	5.52	5.99	5.43
Calgary, AB	11.18	10.46	10.59	10.54	11.14	10.43
Charlottetown, PE ³	11.72	10.99	11.14	11.10	11.72	10.99
Edmonton, AB ⁴	13.94	13.17	11.38	11.26	11.83	11.11
Halifax, NS	13.37	12.70	12.83	12.80	13.37	12.70
Moncton, NB	10.79	9.80	9.53	9.49	10.23	9.35
Ottawa, ON	11.98	11.05	10.97	10.76	11.39	10.60
Regina, SK	10.59	9.57	8.29	8.16	8.67	8.05
St. John's, NL ⁵	10.50	10.18	10.14	6.86	7.31	6.78
Toronto, ON ³	13.21	10.90	11.29	11.12	13.03	10.76
Vancouver, BC	8.74	8.12	6.62	6.60	7.03	6.52
Winnipeg, MB	6.55	6.00	5.18	5.16	5.50	5.09

American Cities

Boston, MA	27.62	25.74	22.66	22.62	23.36	22.48
Chicago, IL	12.26	11.42	9.18	9.15	9.25	9.12
Detroit, MI ³	11.54	10.37	10.16	10.10	10.99	9.93
Houston, TX ³	14.35	13.74	13.03	13.00	13.34	12.93
Miami, FL ³	12.03	11.00	9.74	9.67	10.34	9.53
Nashville, TN	14.03	12.60	8.63	8.36	9.40	8.16
New York, NY ³	23.99	21.27	21.81	21.68	23.96	21.25
Portland, OR ³	12.38	11.76	11.39	11.33	11.81	11.23
San Francisco, CA ³	28.95	26.43	26.59	26.25	28.17	25.84
Seattle, WA	13.59	13.28	12.40	12.32	12.56	12.25
AVERAGE	13.62	12.56	11.78	11.54	12.29	11.39

1) In Canadian currency.

2) Customer-owned transformer.

3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Comparative Index on April 1, 2024
(Hydro-Québec = 100)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage ¹	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%

Canadian Cities

Montréal, QC	100	100	100	100	100	100
Calgary, AB	175	182	191	191	186	192
Charlottetown, PE ²	183	192	201	201	196	202
Edmonton, AB ³	218	230	205	204	198	205
Halifax, NS	209	221	232	232	223	234
Moncton, NB	169	171	172	172	171	172
Ottawa, ON	188	193	198	195	190	195
Regina, SK	166	167	150	148	145	148
St. John's, NL ⁴	164	178	183	124	122	125
Toronto, ON ²	207	190	204	202	218	198
Vancouver, BC	137	142	119	120	117	120
Winnipeg, MB	102	105	93	93	92	94

American Cities

Boston, MA	432	449	409	410	390	414
Chicago, IL	192	199	166	166	155	168
Detroit, MI ²	181	181	183	183	184	183
Houston, TX ²	225	240	235	236	223	238
Miami, FL ²	188	192	176	175	173	176
Nashville, TN	220	220	156	151	157	150
New York, NY ²	376	371	394	393	400	391
Portland, OR ²	194	205	206	205	197	207
San Francisco, CA ²	453	461	480	476	471	476
Seattle, WA	213	231	224	223	210	226
AVERAGE	213	219	212	209	205	210

1) Customer-owned transformer.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.



Appendix

Rate Adjustments

Across-the-Board Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

Across-the-Board Adjustments

	Before April 2023		Between April 1, 2023 and April 1, 2024		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2023	3.00	April 1, 2024	3.00	Applicable to residential customers
			April 1, 2024	5.10	Applicable to all business customers except large-power industrial customers
ENMAX, AB	2023	7.53	January 1, 2024	8.63	Average of distribution (17.88%) and transmission (−0.63%) components
Maritime Electric, PE	2023	NA	May 1, 2023	ND	
			March 1, 2024	ND	
EPCOR, AB	2023	ND	January 1, 2024	ND	
Nova Scotia Power, NS	2023	6.90	January 1, 2024	6.90	
NB Power, NB	2023	5.61	April 1, 2024	9.25	Average increase excluding variance account charge
Hydro Ottawa, ON	2023	ND	November 1, 2023	ND	
			January 1, 2024	ND	
SaskPower, SK	2023	8.00	NA	NA	
Newfoundland Power, NL ¹	2023	−0.30	July 1, 2023	6.90	
Newfoundland and Labrador Hydro, NL ¹	2023	ND	July 1, 2023	ND	
Toronto Hydro, ON	2023	ND	January 1, 2024	ND	
BC Hydro, BC	2023	0.97	April 1, 2024	6.42	
Manitoba Hydro, MB	2023	NA	September 1, 2023	1.00	
			April 1, 2024	1.00	

Data concerning American utilities not available.

NA: Not applicable

ND: No data

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2023, and April 1, 2024)

Adjustments by Customer Category

	Date	Residential Customers %	General-Rate Customers %	Industrial Customers %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2024	3.00	5.10 ¹ 5.10 ² 5.10 ³	3.30	ND
ENMAX, AB	January 1, 2024	8.36 ⁴	8.80 ¹ 8.02 ² 5.29 ³	ND	6.31 ⁴
Maritime Electric, PE	May 1, 2023 March 1, 2024	ND ND	ND ND	ND ND	ND ND
EPCOR, AB	January 1, 2024	ND	ND	ND	ND
Nova Scotia Power, NS	January 1, 2024	6.90	8.40 ¹ 7.10 ² 8.30 ³	8.10 ⁵ 7.90 ⁶	6.90
NB Power, NB	April 1, 2024	9.80	7.50	7.30	9.25
Hydro Ottawa, ON	November 1, 2023 January 1, 2024	2.67 3.63	3.13 3.85	ND -1.02	ND ND
SaskPower, SK	NA	NA	NA	NA	NA
Newfoundland Power, NL ⁷	July 1, 2023	6.60	7.60	9.20	6.90
Newfoundland and Labrador Hydro, NL ⁷	July 1, 2023	NA	NA	0.10	NA
Toronto Hydro, ON	January 1, 2024	ND	ND	ND	ND
BC Hydro, BC	April 1, 2024	6.42	6.42	6.42	6.42
Manitoba Hydro, MB	September 1, 2023 April 1, 2024	1.40 1.40	1.10 1.10	0.50 0.50	1.00 1.00

Data concerning American utilities not available.

NA: Not applicable

ND: No data

1) Small-power customers.

2) Medium-power customers.

3) Large-power customers.

4) Average of distribution and transmission components.

5) Small industrial companies.

6) Midsize industrial companies.

7) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix
Time-of-Use Rates
Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2024 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	Residential customers General-rate customers: 500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General-rate customers: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential customers General-rate customers: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
PacifiCorp, OR	1,000–50,000 kW
Seattle City Light, WA	Residential customers General-rate customers: 1,000–50,000 kW
Toronto Hydro, ON	All levels

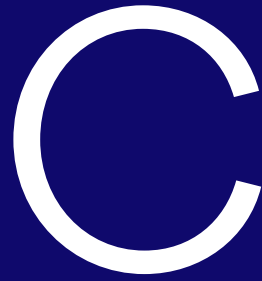
ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	- Deferral Account Rate Rider - Trade Income Rate Rider
CenterPoint Energy, TX	- Accumulated Deferred Federal Income Tax Credit - Distribution Cost Recovery Factor - Energy Efficiency Cost Recovery Factor - Nuclear Decommissioning Charge - Rate Case Expenses Surcharge - Temporary Emergency Electric Energy Facilities Rider - Transition Charges - Transmission Cost Recovery Factor
Commonwealth Edison, IL	- Carbon-Free Resource Adjustment - Delivery Service Pricing Reconciliation - Energy Efficiency Pricing & Performance - Energy Transition Assistance Charge - Environmental Cost Recovery Adjustment - Excess Deferred Income Tax Adjustment - Franchise Cost Additions - Renewable Energy Adjustment - Renewable Energy Distributed Generation Rebate - Retail Customer Assessments - Zero Emission Adjustment
Consolidated Edison, N Y	- Adjustment Factors – MAC - Adjustment Factors – MSC - Clean Energy Standard Delivery Surcharge - Clean Energy Standard Supply Surcharge - Delivery Revenue Surcharge - Dynamic Load Management Surcharge - Market Supply Charge - Market Supply Charge – Capacity - Merchant Function Charge - Monthly Adjustment Clause - Revenue Decoupling Mechanism Adjustment - System Benefits Charge - Value of Distributed Energy Resources Cost Recovery
DTE Electric, MI	- Delivery Surcharges - Energy Waste Reduction Surcharge - Low Income Energy Assistance Fund Factor - Power Supply Cost Recovery Clause - Renewable Energy Plan Surcharge
ENMAX, AB	- Balancing Pool Allocation Rider - Local Access Fee - Quarterly Transmission Access Charge Adjustment Rider - Transmission Access Charge Deferral Account Rider Adjustment

EPCOR, AB	Balancing Pool Rider DAS True-Up Rider Local Access Fee SAS True-Up Rider Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Advanced Metering Infrastructure Factor Attorney General Consultant Expense Basic Service Cost Adjustment Electronic Payment Recovery Factor Energy Efficiency Charge Farm Discount Grid Modernization Factor Long Term Renewable Contract Adjustment Low Income Discount Miscellaneous Charges Net Metering Recovery Surcharge Pension Adjustment Mechanism Performance Based Revenue Adjustment Provisional System Planning Factor Renewable Energy Charge Residential Assistance Adjustment Clause Revenue Decoupling Adjustment Mechanism Solar Expansion Cost Recovery Mechanism Solar Massachusetts Renewable Target Solar Program Cost Adjustment Storm Cost Recovery Adjustment Storm Reserve Adjustment Mechanism Transition Cost Adjustment Transmission Service Cost Adjustment Vegetation Management 2017 Tax Act Credit
Florida Power and Light, FL	Capacity Payment Recovery Clause Energy Conservation Cost Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Protection Charge Transition Rider Credit
Hydro Ottawa, ON	Capacity Based Recovery Charge Disposition of Capacity Based Recovery Account Disposition of Deferral/Variance Accounts Disposition of Deferral/Variance Accounts (2023) Disposition of Global Adjustment Account Lost Revenue Adjustment Mechanism Recovery Rate Rider for Disposition of Class B Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	Small Manufacturing Credit Tax Exemption Status

Newfoundland and Labrador Hydro, NL	CDM Cost Recovery Adjustment Rider Rate Stabilization Plan Adjustment Rider
Nova Scotia Power, NS	Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	Bundled Power Charge Indifference Adjustment California Climate Credit Competition Transition Charges Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Recovery Bond Charge/Credit Reliability Services Transmission Rate Adjustments Wildfire Fund Charge Wildfire Hardening Charge
PacifiCorp, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act Base Supply Service Community Solar Start-Up Cost Recovery Adjustment Deferred Accounting Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Low Income Bill Payment Assistance Fund Multnomah County Business Income Tax Recovery Net Power Costs, Cost-Based Supply Service Oregon Solar Incentive Program Deferral Power Cost Adjustment Mechanism Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral Adjustment Replaced Meter Deferred Amounts Adjustment System Benefits Charge TAM Adjustment for Other Revenues Wildfire Mitigation and Vegetation Management Cost Recovery Adjustment Wildfire Protection Plan Cost Recovery Adjustment
Toronto Hydro, ON	Capacity Based Recovery (CBR) Disposition of Accounts Receivable Credits Disposition of Capacity Based Recovery Account Disposition of Capital Related Revenue Requirement Variance Account Disposition of Deferral/Variance Account Disposition of Expansion Deposits Disposition of PILs and Tax Variance Disposition of Stranded Meter Assets Disposition of Wireless Pole Attachment Revenue Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge



Appendix

Applicable Taxes

Residential Customers

General-Rate Customers

Industrial Customers

TAXES APPLICABLE TO RESIDENTIAL CUSTOMERS

On April 1, 2024

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	\$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (customers with electric heating)
		7	To base amount of bill (customers with heating other than electric)
	Municipal tax	0.5	To base amount of bill (customers with electric heating)
		2.5	To base amount of bill (customers with heating other than electric)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	¢/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	4	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.6509	To base amount of bill
	Franchise fee	5.273	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	4.5485	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	-0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS

On April 1, 2024

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable ¹⁾)
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (mining and manufacturing companies)
		7	To base amount of bill (industries other than mining and manufacturing)
		1	To base amount of bill (customers with electric heating)
		5	To base amount of bill (customers with heating other than electric)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	¢/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill

1) Business customers with revenue below \$10 million and all customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS (cont'd)

On April 1, 2024

	Tax	% (or other)	Applicable
Miami, FL	Gross receipts tax	2.6509	To base amount of bill
	Franchise fee	5.273	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.2195	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	-0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS

On April 1, 2024

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable ¹)
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (mining and manufacturing companies)
		7	To base amount of bill (industries other than mining and manufacturing)
		1	To base amount of bill (customers with electric heating)
		5	To base amount of bill (customers with heating other than electric)
	Municipal tax		
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	¢/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill

1) Business customers with revenue below \$10 million and all customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS (cont'd)

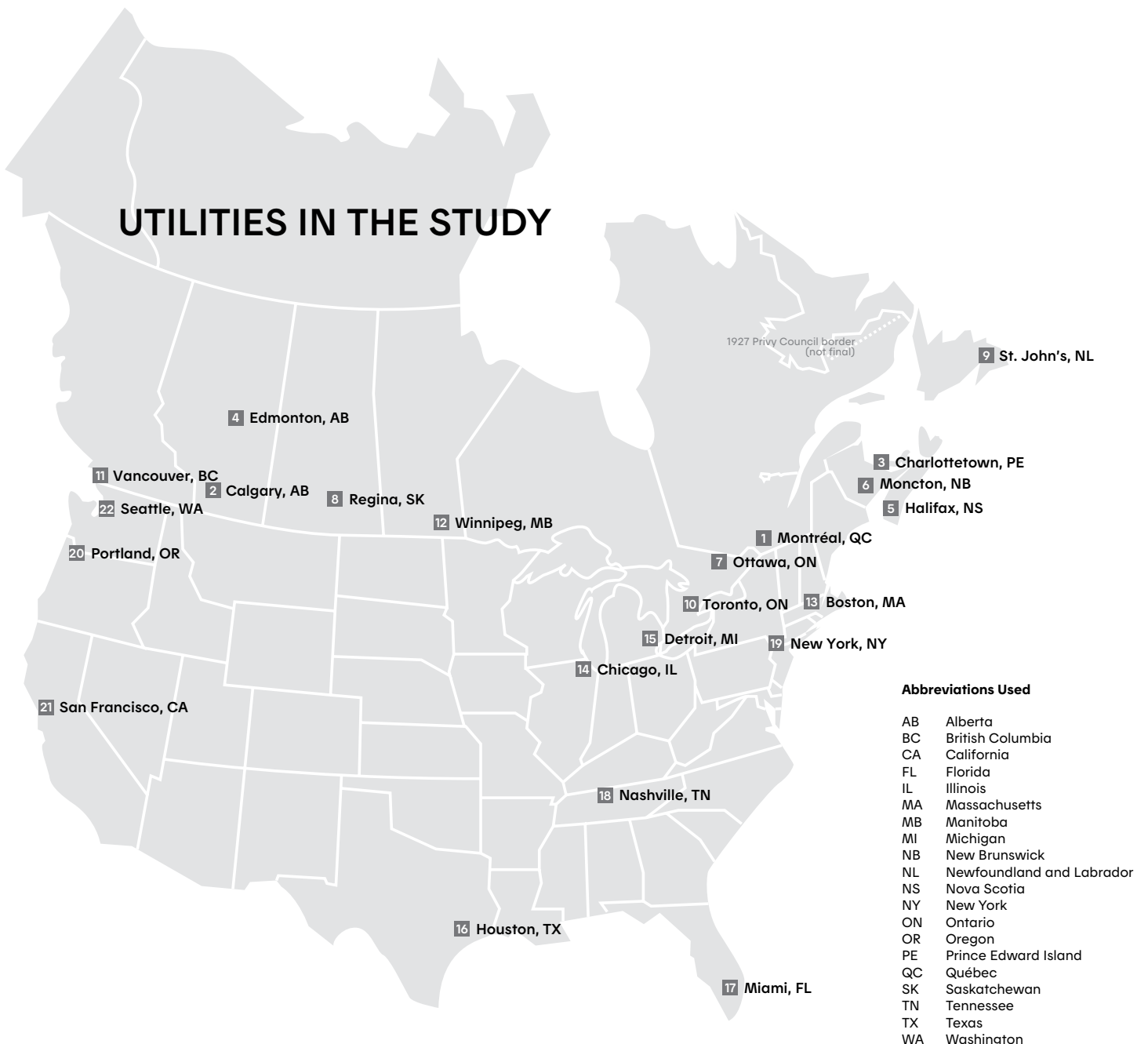
On April 1, 2024

	Tax	% (or other)	Applicable
Miami, FL	Gross receipts tax/	2.6509	To base amount of bill
	Franchise fee	5.273	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.2195	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	-0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

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Appendix Utilities in the Study

UTILITIES IN THE STUDY



CANADIAN UTILITIES

- 1- Hydro-Québec
- 2- ENMAX
- 3- Maritime Electric
- 4- EPCOR
- 5- Nova Scotia Power
- 6- NB Power
- 7- Hydro Ottawa
- 8- SaskPower
- 9- Newfoundland and Labrador Hydro
(customers with a power demand
of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
- 10- Toronto Hydro
- 11- BC Hydro
- 12- Manitoba Hydro

AMERICAN UTILITIES

- 13- Eversource Energy
- 14- Commonwealth Edison
- 15- DTE Electric
- 16- CenterPoint Energy
- 17- Florida Power and Light
- 18- Nashville Electric Service
- 19- Consolidated Edison
- 20- PacifiCorp
- 21- Pacific Gas and Electric
- 22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC

Montréal, Québec

Hydro-Québec, a government-owned company, is one of the largest electric utilities in North America. In accordance with the *Act respecting the Régie de l'énergie* [Québec energy board], it provides a maximum of 165 TWh of heritage pool electricity per year to the Québec market and also purchases power on the markets to meet its customers' needs. The average supply cost of heritage pool electricity, set at 2.79¢/kWh in 1998, has been indexed annually on January 1 since 2014 at a rate corresponding to the annual variation in the average overall Consumer Price Index for Québec. The large-power industrial rate (Rate L) is exempt from this indexation.

Pursuant to *An Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity*, the company's distribution rates were increased as follows on April 1, 2024:

- 3.0% for residential customers;
- 5.1% for all other customers except large-power industrial customers;
- 3.3% for large-power industrial customers (5.1% increase multiplied by an adjustment factor of 0.65 set by the Régie de l'énergie).

Activities: Generation, transmission and distribution

Installed capacity: 37,436 MW

Main sources: Hydropower generating stations and wind power purchases (more than 99% of power supplied is clean and renewable)

Number of accounts: About 4.55 million residential, commercial, institutional and industrial customer accounts, nine municipal systems and one regional cooperative

Distribution regulator: Régie de l'énergie

Wholesale market: Open

Retail market: Not applicable

ENMAX

Calgary, Alberta

Activities: Generation, transmission and distribution

Installed capacity: 1,638 MW

Main sources: Natural gas (91%) and wind (9%)

Number of accounts: More than 747,000

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

MARITIME ELECTRIC

Charlottetown, Prince Edward Island

Activities: Distribution

Installed capacity: 203 MW

Main sources: Purchases from NB Power and PEI Energy Corporation

Number of accounts: More than 89,000

Distribution regulator: Island Regulatory and Appeals Commission

Wholesale market: Not applicable

Retail market: Not applicable

EPCOR

Edmonton, Alberta

Activities: Transmission and distribution

Installed capacity: Not applicable

Main sources: Market purchases

Number of accounts: About 435,000 customers in Edmonton

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

NOVA SCOTIA POWER

Halifax, Nova Scotia

Activities: Generation, transmission and distribution

Installed capacity: 2,422 MW

Main sources: Thermal (coal, natural gas, petroleum and petroleum coke), hydropower, wind and other

Number of accounts: More than 549,000 residential, commercial and industrial customers

Distribution regulator: Nova Scotia Utility and Review Board

Wholesale market: Not applicable

Retail market: Not applicable

NB POWER

Moncton, New Brunswick

Activities: Generation, transmission and distribution

Installed capacity: 3,800 MW

Main sources: Thermal (1,723 MW), hydropower (886 MW), nuclear (663 MW) and combustion turbines (525 MW)

Number of accounts: About 430,000

Distribution regulator: New Brunswick Energy and Utilities Board

Wholesale market: Not applicable

Retail market: Not applicable

HYDRO OTTAWA

Ottawa, Ontario

Activities: Generation and distribution

Installed capacity: 131 MW (renewable energy)

Main sources: Purchases from Ontario Power Generation

Number of accounts: About 364,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but electricity supply rate regulated by the Ontario Energy Board

SASKPOWER

Regina, Saskatchewan

Activities: Generation, transmission and distribution

Installed capacity: 5,437 MW

Main sources: Natural gas (40%), coal (25%), hydropower (21%), wind (11%), solar (2%) and other (1%)

Number of accounts: 557,443

Distribution regulator: Saskatchewan Rate Review Panel

Wholesale market: Partially open

Retail market: Partially open

NEWFOUNDLAND AND LABRADOR HYDRO

(customers with a power demand of 30,000 kW or more)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 2,616 MW

Main sources: Hydropower (89%) and thermal (11%)

Number of accounts: More than 38,800

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: Not applicable

Retail market: Not applicable

NEWFOUNDLAND POWER

(all other customer categories)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 140 MW

Main sources: Purchases from Newfoundland and Labrador Hydro (93%)

Number of accounts: About 275,000 customers throughout the island of Newfoundland

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: Not applicable

Retail market: Not applicable

Toronto, Ontario

Installed capacity: Not applicable

Number of accounts: About 793.000

Wholesale market: Open

BC HYDRO

Vancouver, British Columbia

Installed capacity: About 12,214 MW

Main sources: Hydropower (about 98%)

Number of accounts: Nearly 2.2 million

Wholesale market: Open

Retail market: Not applicable

Winnipeg, Manitoba

Installed capacity: 6,054 MW

Number of accounts: About 616,000

Wholesale market: Not applicable

Retail market: Not applicable

EVERSOURCE ENERGY

Boston, Massachusetts

Installed capacity: Not applicable

Main sources: Purchases from ISO New England

Distribution regulator: Massachusetts Department of Public Utilities

Wholesale market: Open

Retail market: Open

Chicago, Illinois

Installed capacity: Not applicable

Number of accounts: Nearly 4.1 million customers in northern Illinois

Wholesale market: Open

Retail market: Open

Detroit, Michigan

Installed capacity: 11,084 MW

Number of accounts: 2.3 million customers in southeastern Michigan

Distribution regulator: Michigan Public Service Commission

Wholesale market: Open

Retail market: Partially open

Houston, Texas

Installed capacity: More than 1,200 MW

Main sources: Purchases from the Electric Reliability Council of Texas

Number of accounts: Nearly 2.9 million

Distribution regulator: Public Utility Commission of Texas

Wholesale market: Open

Retail market: Open

Miami, Florida

Installed capacity: Over 33,200 MW

Main sources: Natural gas, nuclear, solar and coal

Number of accounts: More than 5.9 million

Distribution regulator: Florida Public Service Commission

Wholesale market: Open

Retail market: Not applicable

Nashville, Tennessee

Installed capacity: Not applicable

Main sources: Purchases from Tennessee Valley Authority

Number of accounts: About 448,000

Distribution regulator: Tennessee Valley Authority

Wholesale market: Not applicable

Retail market: Not applicable

New York, New York

Installed capacity: Not applicable

Main sources: Purchases from New York Independent System Operator

Number of accounts: About 3.7 million customers in the New York metropolitan area and in Westchester County

Distribution regulator: New York State Public Service Commission

Wholesale market: Open

Retail market: Open

Portland, Oregon

Installed capacity: 10,833 MW

Main sources: Thermal (natural gas and coal), hydropower, wind, solar and geothermal

Number of accounts: 800,000 customers across three states (Oregon, Washington and California)

Distribution regulator: Public Utility Commission of Oregon

Wholesale market: Open

Retail market: Partially open

San Francisco, California

Installed capacity: 7,820 MW

Number of accounts: 5.5 million

Wholesale market: Open

Retail market: Partially open

Seattle, Washington

Installed capacity: 2,006.4 MW

Number of accounts: Nearly 503,200 customers in Seattle and surrounding communities

Wholesale market: Open

Retail market: Not applicable

Annual reports and websites of the Canadian and American utilities in the study.

Legal Deposit, Bibliothèque et Archives nationales du Québec, 4th quarter 2024
ISBN : 978-2-550-99040-6 (PDF v. ang.)
ISBN : 978-2-550-99039-0 (PDF v. fr.)

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This publication is available online at
www.hydroquebec.com/documents-data/official-publications.

Original document written in French.
Ce document est également publié en français.

2024G391A