



Management's Discussion and Analysis  
For the Fiscal Year Ended March 31, 2026

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## Organizational Overview

### *Introduction and Basis of Presentation*

Rockpoint Gas Storage Inc. (“Rockpoint” or the “Company”) was formed on July 28, 2025 for the purpose of completing an initial public offering of class “A” common shares (“Class A Shares”) and acquiring a 40% interest in the gas storage business carried on collectively by Swan Equity Aggregator LP (“Swan OpCo”), including its wholly owned subsidiaries Warwick Gas Storage LP and Warwick Gas Storage Ltd. (collectively “WGS LP”), and BIF II CalGas (Delaware) LLC (“BIF OpCo” and together with Swan OpCo and each of their wholly owned subsidiaries, the “OpCos”), as well as BIF II SIM Limited, SIM Energy LP and SIM Energy Limited (collectively “SIM”), and Swan Debt Aggregator LP (“Swan Debt”) (collectively, “we”, “us”, “our”, or the “Business”). Rockpoint’s acquisition of the 40% interest in the Business was completed on October 15, 2025, see “Notable Transactions”.

The Business consists of entities that are ultimately controlled by Brookfield Asset Management Private Institutional Capital Advisor (Canada), L.P. (“Brookfield Infrastructure”, and together with its affiliates (other than Rockpoint, the OpCos, and any of their direct and indirect subsidiaries) “Brookfield”).

This Management’s Discussion and Analysis (“MD&A”) is dated May 27, 2026 and discusses the financial position of the Business as at March 31, 2026 and March 31, 2025, and results of operations of the Business for the three and twelve months ended March 31, 2026 and 2025, as well as the results of operations of the Company for the three months ended March 31, 2026, and for the period beginning July 28, 2025 and ended March 31, 2026.

This MD&A should be read in conjunction with the Business’ audited combined consolidated financial statements for the fiscal years ended March 31, 2026 and March 31, 2025, as well as the Company’s audited financial statements for the period beginning July 28, 2025 and ended March 31, 2026. The Company was formed on July 28, 2025. Therefore, no comparative financial information is provided in respect of the Company.

All financial information contained in this MD&A, unless stated otherwise, has been prepared in accordance with IFRS Accounting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”), representing generally accepted accounting principles for publicly accountable enterprises in Canada, using the accounting policies described in Note 3 in each of the financial statements of the Business and Company as well as the accounting policies outlined in “Material Accounting Policies and Estimates and Changes in Accounting Policies” within this MD&A. This MD&A is presented in millions of United States dollars (“USD”) unless otherwise noted. References to “C\$” are to Canadian dollars.

This MD&A contains statements that are forward-looking in nature and readers should refer to “Forward-Looking Information”.

#### *Non-IFRS Financial Measures*

Certain financial measures have been identified that management believes provide meaningful information in the Business’ underlying performance. The Company cautions readers that such measures do not have standardized meanings under IFRS and may therefore not be comparable to similarly titled measures presented by other entities. For a list and description of non-IFRS measures, as well as how we reconcile these measures to IFRS derived information, readers should refer to “Non-IFRS Measures Utilized by Our Business”.

#### ***Business Overview***

We are a natural gas storage operator with a portfolio consisting of six facilities located across California and Alberta with total effective working gas storage capacity of approximately 279.2 billion cubic feet (“Bcf”). We estimate that our total effective working gas storage capacity represents approximately one third of the combined storage market in Alberta and California. Our facilities are strategically located and are interconnected with several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs. We also operate a natural gas marketing business that is an extension of our proprietary optimization activities in Canada.

In Alberta, we own and operate: (i) the AECO Hub™ which is comprised of two facilities (Suffield and Countess) with 154.0 Bcf of combined effective working gas storage capacity; and (ii) the Warwick storage facility with 21.5 Bcf of effective working gas storage capacity. In California, we own and operate: (i) the Wild Goose storage facility with 75.0 Bcf of effective working gas storage capacity; and (ii) the Lodi and Kirby Hills storage facilities with 28.7 Bcf of combined effective working gas storage capacity.

We define “effective working gas storage capacity” as the maximum volume of natural gas that can be stored in an underground storage facility in accordance with its design less base gas, where base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Management conducts its own estimates for total effective working gas storage capacity and routinely commissions third-party reservoir analyses of its reservoirs to validate the reservoir operating parameter.

#### *Our History*

Our asset portfolio has a 38-year operational history with the AECO Hub™ commencing operations in 1988. Our strategic development has been shaped by three key storage facility acquisitions, which have defined our extensive operational footprint in North America. The acquisition of Warwick in 2012 marked Brookfield’s initial entry into the Alberta market, providing a foundation for potential subsequent expansion. In 2014, the acquisition of Lodi and Kirby Hills established Brookfield’s presence in California, offering essential storage facilities integral to the region’s energy infrastructure and the acquisition of the AECO Hub™ and Wild Goose in 2016 firmly established our position as a leading independent owner and operator of natural gas storage infrastructure in North America.

### *Importance of Natural Gas Storage*

Natural gas storage infrastructure plays a crucial role in the natural gas value chain to ensure supply meets demand throughout the year. It bolsters production and delivery systems, providing a reliable supply during periods of high demand and enabling the injection of supplemental production during low demand or off-peak times. This process balances steady production with fluctuating daily, monthly, and seasonal consumption. When production exceeds demand, typically in summer, excess gas is stored; conversely, during winter, stored gas is withdrawn to meet increased demand. Natural gas storage acts as the critical balancing mechanism to manage supply disruption and maintain orderly markets. We define a gas market as being “tight” if demand exceeds available supply. According to industry sources such as the U.S. Energy Information Administration (“EIA”), in the coming years, natural gas demand is expected to grow, driven primarily by: (i) the expansion of liquified natural gas (“LNG”) exports; (ii) continued build out of gas-to-power infrastructure to support data centre growth and electrification broadly; and (iii) the need for flexible gas-fired power generation to support intermittent renewable energy sources. We believe that increased demand for natural gas will create a significant structural tightening in the North American market. North American natural gas demand in 2025 was approximately 129 Bcf/d, up from approximately 92 Bcf/d in 2016<sup>1</sup>. We expect this upward demand trend to continue, reaching an anticipated 157 Bcf/d by 2030, based on our assessment of LNG export and domestic consumption forecasts prepared by industry sources such as the Canada Energy Regulator (“CER”), EIA and S&P Global Energy. A tighter gas market typically translates into increased natural gas price volatility and the potential for significant short term supply disruptions.

The North American natural gas storage market is comprised of more than 400 storage facilities with effective working gas capacity of approximately 5.6 trillion cubic feet (“Tcf”)<sup>2</sup>. We believe existing gas storage infrastructure will be critical to meet future structural changes in natural gas demand. There have been minimal additions to gas storage over the past decade with significant geographic, regulatory and interconnection barriers hindering new development. Assuming completion of all U.S. storage projects and expansions currently in development (and no other projects or expansions in North America being completed), we expect North American effective working gas storage capacity to be approximately 6.0 Tcf by 2030, which is virtually unchanged relative to capacity today. We believe this scarcity of capacity competitively positions current storage owners and operators, including us, to benefit from strong market fundamentals and upward pressure on storage rates. The value of natural gas storage services and associated storage rates are principally based on four components: (i) operational and location characteristics of the storage facility; (ii) seasonal value in natural gas prices; (iii) insurance value of storage, representing a premium the market allocates to mitigate gas pricing volatility; and (iv) demand factor. The relationship between these components in determining the value of storage is seasonal value plus the insurance value of storage plus the demand factor, where the operational characteristics of the facility (i.e., the ability to efficiently and reliably respond and the demand elasticity) can act as a multiplier on the seasonal value and insurance value components.

### *Outlook for our Business*

As global natural gas demand continues to grow, the role of gas storage in balancing supply and demand variations has become even more important. The lack of new gas storage development has created scarcity value for existing storage assets, which has translated into higher storage rates for existing facilities. Our assets are strategically located within the North American natural gas logistics network, and we believe are well positioned to benefit from strong market fundamentals and structural drivers of demand, including reindustrialization and energization of the North American grid, increasing reliance on intermittent renewables generation, and global gas pricing exposure through rising LNG exports. As a result, we expect to see significant growth from contract renewals in a rising rate environment further supported by new customer demand. We utilize the measures of Adjusted EBITDA and Distributable Cash Flow, see “Non-IFRS Measures Utilized by Our Business”. Our appraisal of the foregoing factors has allowed us to implement a long-term annual Adjusted EBITDA growth target of 4% to 5%, driven by higher contract pricing, which we expect to translate to an annual Distributable Cash Flow growth target of 5% to 6%. In addition, we believe that our growth outlook can be further enhanced by accretive capital projects, as well as strategic optionality from various opportunities, including but not limited to future acquisitions and portfolio and balance sheet optimization. Based on the foregoing, we are also targeting incremental annual Distributable Cash Flow growth of 4% to 5% over the long-term in the event that such growth projects and opportunities are consummated.

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<sup>1</sup> Sources: EIA, CER and S&P Global Energy

<sup>2</sup> Sources: EIA and CER

## ***Our Commercial Model***

### *Fee-for-Service Revenue*

Fee-for-service (“Fee-for-Service”) revenue consists of longer-term firm storage services (“Take-or-Pay” or “ToP”) contracts (typically ranging from one to ten years) and Short-term Storage service (“STS”) contracts (typically spanning up to one storage season with a strong history of contract renewals). Our Fee-for-Service revenue is underpinned by a diverse and high-quality customer base that stores customer-owned gas volumes in our storage facilities. Our strong performance not only reflects the resilience and attractiveness of our commercial model but also reinforces our strategic positioning in the market, enabling predictable cash flows and long-term value creation.

Under ToP contracts, our customers are obligated to pay a fixed monthly demand charge for storage capacity regardless of utilization. Customers have the right, but not the obligation, to inject, store or withdraw a predetermined amount of gas as specified in each contract. We receive the monthly demand charge regardless of the actual capacity utilized by our customers. When customers utilize reserved capacity under these contracts, we receive additional variable fees based on the actual volumes of natural gas injected or withdrawn.

Under STS contracts, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas. Revenue from STS contracts is recognized 50% on injection and 50% on withdrawal. Unlike ToP contracts, STS contracts require customers to inject and withdraw specified quantities on specified, predetermined dates. STS contracts enable us to secure value by capturing the seasonal value of the price difference between summer and winter months net of the customer’s required return on the transaction. Because STS contracts specify predetermined injection and withdrawal volumes at predetermined rates, they also allow us to opportunistically enter into offsetting transactions to capture incremental storage value as spot and future natural gas spreads fluctuate prior to the original transaction’s specified withdrawal date.

### *Optimization Revenue*

We utilize a small portion of our storage capacity through a storage optimization strategy which is intended to provide us the flexibility to first manage our firm Fee-for-Service customer obligations as needed and then to capture market opportunities as they arise. Storage optimization involves purchasing, storing and selling natural gas for our own account, using our own corporate liquidity, for profit. As per our risk policy, we are allowed to carry only very limited open positions that expose us to price or physical delivery risk. We aim to eliminate market price risks by matching inventory purchases with physical and financial contracts, effectively locking in margins at the time of injection. As a result, our activities remain non-speculative, operating strictly within defined operational risk tolerances. Our storage optimization strategy has proven to be valuable in allowing us to capture seasonal spread value and subsequently generate incremental gross margin from natural gas price volatility.

We also provide natural gas marketing and transportation services in Canada through Access Gas Services Inc., Access Gas Services (Ontario) Inc. and EnerStream Agency Services Inc., which are included in our optimization activities.

## ***Principal Components of Our Cost Structure***

### *Operating Expenses*

Our operating expenses include components that are largely fixed in nature and those that are variable. The largely fixed components of our operating expenses include salaries and labor, parts and supplies, and other general operating costs. These operating expenses are relatively stable from year to year but can vary within a narrow range due to factors such as inflation and heavy facility usage.

The largest components of our variable operating costs are the costs of natural gas and electricity used to power our compressors. These items are affected by the amount and price of energy used to inject and withdraw natural gas from our facilities and by the frequency and timing of gas injections and withdrawals. For example, if we experience large injections of natural gas in the early summer (instead of a steady rate of injections throughout the summer), we will have higher costs in our first quarter and lower costs in the second quarter. A mild winter could lead to fewer withdrawals in total, and therefore lower overall fuel and power costs due to fewer injections required to fill our storage facilities the following summer. Fuel and utilities cost savings can be realized when simultaneous injections and withdrawals occur. This dynamic requires no physical gas flow in or out of the facility which allows us to reduce the usage of our compressors. Variable operating expenses are partially offset by the variable fees we collect from our ToP customers.

We also have variable costs that are driven by our revenues. Land lease agreements with certain landowners in California increase or decrease as a direct result of changes in revenues generated. Certain property tax related facility valuations include income-based components. There can be time lags in changes in property taxes as property value assessments may not line up with the same period in which revenues were generated.

#### *General and Administrative*

Our general and administrative expenses primarily consist of employee and contractor compensation, professional fees, and other general costs.

#### ***Seasonality of the Business***

Natural gas seasonality is a key feature of the energy market, driven by temperature-induced demand fluctuations. As natural gas is used to meet heating needs, demand typically peaks in winter and declines in summer. In comparison to our ToP contracting, where revenue is typically earned evenly over a fiscal year, our optimization and STS revenue strategies can be impacted by seasonal variation. Our optimization revenues are normally highest during the withdrawal season (typically November through March), as we generally position our inventory sales hedges to coincide with the highest demand for natural gas. In addition, our STS revenue strategy tends to be weighted to the shorter withdrawal season versus the longer injection season (typically April to October). As a result of these factors, a moderately higher proportion of our revenues is typically recognized within our third and fourth fiscal quarters.

Seasonality can have a moderate impact on our cash flows. We normally purchase our proprietary optimization natural gas inventories throughout the injection season and position sales in the winter months. As a result, borrowings under our revolving credit facilities tend to peak at the beginning of the withdrawal season. In contrast, our cash inflows tend to increase one month after the withdrawal season begins (because collections of cash occur on or around the 25th day following month-end) and therefore our cash inflows tend to be highest from December to April.

#### ***Financial Policy and Principles***

We strive to adhere to a conservative financial policy, which we believe is essential in generating a stable and growing Distributable Cash Flow profile, maintaining a high rate of cash conversion, managing corporate liquidity and ensuring downside protection for our investors and stakeholders.

The key pillars of our financial principles are as follows:

##### *Generate the vast majority of our cash flows from Fee-for-Service contracts*

We target 85% Fee-for-Service cash flows with investment grade and highly credit worthy counterparties. We believe this is critical in providing cash flow stability as well as reducing the capital intensity of our operations.

##### *Provide a balanced payout ratio to our shareholders*

We are committed to delivering a 50-60% payout of our Distributable Cash Flow to our shareholders primarily generated from ToP cash flows. We expect Distributable Cash Flow to grow over time, both organically through recontracting and through the execution of our growth initiatives.

### *Maintain high levels of liquidity*

As at March 31, 2026, our Business had \$361.2 million of available liquidity, which was comprised of \$42.3 million of available cash and cash equivalents, which excludes restricted cash, and \$318.9 million of undrawn and available capacity on our revolving credit facilities, see “Liquidity and Capital Resources”. Our Business has few non-discretionary growth and maintenance capital requirements and thus our available liquidity is reserved to reinvest into growth initiatives intended to enhance our storage service offerings, fund working capital, provide our shareholders a stable and growing dividend and to opportunistically repurchase shares when we believe there is a disconnect between our intrinsic value and market valuation.

### *Conservative capitalization of our balance sheet*

We maintain a prudent level of long-term capitalization through our Term Loan due 2031, which can be prepaid at par without penalty, except for a 1.00% premium applied as a result of voluntary prepayments that occur within six months of a repricing event, the last of which occurred on May 7, 2026. We believe this provides us with the flexibility to adjust our capitalization in response to changing financial conditions, if required.

In addition, we target leverage at, or below, 3.5x of Net Debt, see “Non-IFRS Measures Utilized by Our Business”, to Adjusted EBITDA over the near-term, which we believe is appropriate for our existing business model. The Business is currently rated as ‘BB’ with a ‘Stable’ outlook by S&P and ‘B1’ with a ‘Positive’ outlook by Moody’s. Over the medium-term, we target credit rating improvements through continued enhancements to our contractual profile.

## **Notable Transactions**

### *Warwick Acquisition and Repayment and Termination of Warwick Credit Facility*

On October 14, 2025, AECO Gas Storage Partnership (“AECO”), a subsidiary of Swan OpCo, acquired 100% of the equity interests in WGS LP from BAIF Warwick Storage L.P., a Brookfield owned and operated entity. The acquisition was funded through a loan from affiliates of Brookfield Infrastructure, which was ultimately converted to an equity contribution in the Business.

As part of the Warwick Acquisition, AECO funded the repayment of the then outstanding \$9.4 million (C\$13.2 million) balance on WGS LP’s credit facility, which had an aggregate principal amount available of C\$37.5 million (the “Warwick Credit Facility”). Subsequently, the Warwick Credit Facility was cancelled.

### *Offerings*

On October 15, 2025, the Company completed its initial public offering of 32,000,000 Class A Shares at a price of C\$22.00 (approximately \$15.66) per Class A Share (the “Offering Price”) for gross proceeds of C\$704.0 million (\$501.2 million) (the “Offering”). In addition, the underwriters exercised their over-allotment option (the “October 2025 Secondary Offering”) in full to acquire an additional 4,800,000 Class A Shares at the Offering Price from Brookfield for gross proceeds of C\$105.6 million. The Company did not receive any of the proceeds from the October 2025 Secondary Offering.

On February 23, 2026, 16,400,000 Class A Shares held by Brookfield, representing all of Brookfield’s then remaining Class A Shares, were sold to the public (the “February 2026 Secondary Offering”). The Company did not receive any proceeds from the February 2026 Secondary Offering.

### *Investment in and Reorganization of the Business*

On October 15, 2025, immediately following the Offering, Rockpoint acquired a 40% interest in the Business undertaken by Swan OpCo and BIF OpCo from Brookfield in exchange for aggregate consideration of \$882.0 million, which was satisfied by the Company through settlement of a payable of \$504.6 million (on which it realized a \$3.4 million foreign exchange gain), and the issuance of 21,200,000 Class A Shares at a fair market value of \$377.4 million.

Also following the completion of the Offering, on October 15, 2025, the Company issued 79,800,000 class “B” voting shares (the “Class B Shares”) to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration to align the voting interest of Brookfield Infrastructure and certain of its affiliates in the Company with its economic interest in the OpCos.

Following the completion of the Offering, the October 2025 Secondary Offering, and the February 2026 Secondary Offering, as of March 31, 2026, Brookfield owned no Class A Shares and 79,800,000 Class B Shares, representing 0% and 100% of the outstanding Class A Shares and Class B Shares, respectively, and 60% of the votes attached to the 133,000,000 total outstanding shares of the Company.

#### *Revolving Credit Facility and Repayment and Termination of ABL Facility*

On October 15, 2025, Rockpoint, Rockpoint Gas Storage Partners LP, Rockpoint Gas Storage LLC and AECO, as borrowers, entered into a credit agreement (the “Revolving Credit Agreement”) establishing a new senior secured revolving credit facility (the “Revolving Credit Facility”), which matures on October 15, 2030. The Revolving Credit Facility has an aggregate commitment available of \$350.0 million, including a letters of credit sub-limit of \$175.0 million. Concurrent with entering into the Revolving Credit Agreement, the Business repaid in full and terminated its asset backed loan, which had a maximum limit of \$250.0 million in drawings of cash and letters of credit (the “ABL Facility”). See “Liquidity and Capital Resources”.

#### *Legal Structure Reorganization*

Immediately following completion of the Offering, Rockpoint Gas Storage Canada Ltd., an indirect subsidiary of Swan OpCo, acquired SIM and Swan Debt. The fair market values of SIM Energy LP, SIM Energy Limited and Swan Debt Aggregator LP were negligible prior to their transfer and each entity was therefore transferred at a nominal value of \$1. The Business paid a cumulative total to Brookfield of \$2.8 million for BIF II SIM Limited which represented the fair market value of that entity, mainly consisting of cash on hand. During December 2025, the SIM entities, Swan Debt as well as Rockpoint Canada Inc. (a dormant entity) were dissolved. The assets and liabilities of these entities were assumed by Rockpoint Gas Storage Canada Ltd. with no impact on the Business’ consolidated balances.

#### *Term Loan due 2031 Hedging and Repricing*

On October 24, 2025, the Business entered into new interest rate swap contracts that hedge the entire projected principal borrowings over the term of the senior secured term loan B facility in an original aggregate principal amount of \$1,250.0 million (the “Term Loan due 2031”) for balances drawn using secured overnight financing rate (“SOFR”) loans. Together with an October 29, 2025 repricing of the Term Loan due 2031, which reduced the interest rates on SOFR and base rate drawn loans by 0.50% in each case, the loan had an effective all-in interest rate of 5.90% as of March 31, 2026 on SOFR drawn balances. See “Liquidity and Capital Resources”.

Effective May 7, 2026, the Term Loan due 2031 was again repriced to achieve a reduction of 0.25% to both SOFR and base rate denominated loans, see “Liquidity and Capital Resources”. The repricing is expected to reduce the Business’ annual interest costs by approximately \$3.0 million per year over the remaining term of the loan, which will impact the Company’s earnings from its equity investment on a proportionate basis to its ownership.

#### *Legacy Incentive Plan Payments*

In March 2026, Brookfield’s long-term incentive plan agreements (“Legacy Incentive Plans”) with certain officers, employees and former employees were amended to facilitate partial payments of amounts thereunder. The Legacy Incentive Plans were established at the inception of Brookfield’s investments in the Business. All amounts paid in respect of these plans were funded by Brookfield and any future amounts that may become due will also be funded by Brookfield, and therefore, will not impact the liquidity of the Business or the Company. In connection with this amendment to the Legacy Incentive Plans, in March 2026, aggregate payments totaling \$51.5 million were made, including amounts related to the initial public offering of the Company in October 2025 and the February 2026 Secondary Offering, and recorded to other expenses in the combined consolidated financial statements of the Business. The payments were funded by a \$51.5 million capital contribution from Brookfield during the same month. This capital contribution did not provide Brookfield with additional rights to future earnings of the Business. Any future payments related to Legacy Incentive Plans are contingent upon future sales of economic interest held in the Business by Brookfield, and therefore, no additional obligations have been recognized by the Business.

## Results of Operations and Financial Results of the Business

The following table sets forth the results of operations of the Business for the three and twelve months ended March 31, 2026 and 2025:

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
<b>REVENUES</b>				
Fee-for-Service revenue	\$ 103.0	\$ 109.4	\$ 388.5	\$ 366.8
Optimization, net	21.9	18.7	90.9	48.5
Total revenues	124.9	128.1	479.4	415.3
<b>EXPENSES (INCOME)</b>				
Cost of gas storage services	3.6	5.2	8.2	11.0
Operating	13.2	13.8	50.8	49.5
General and administrative	6.5	7.8	22.2	24.2
Depreciation and amortization	7.7	7.7	34.1	33.1
Financing costs	16.2	29.7	89.8	93.1
(Gain) loss on gas storage obligations, net	(1.4)	0.3	(4.5)	(1.3)
Other expenses	52.4	1.7	55.3	6.9
<b>EARNINGS BEFORE INCOME TAXES</b>	26.7	61.9	223.5	198.8
Income tax expense (benefit)				
Current	3.0	—	6.1	0.6
Deferred	(0.7)	4.9	10.5	(11.2)
<b>NET EARNINGS</b>	\$ 24.4	\$ 57.0	\$ 206.9	\$ 209.4

### Fee-for-Service revenue

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
<b>Fee-for-Service revenue</b>	\$ 103.0	\$ 109.4	\$ 388.5	\$ 366.8
Take-or-Pay contract revenue	58.7	46.5	233.6	185.0
Short-term Storage service revenue	44.3	62.9	154.9	181.8

Total revenues include Fee-for-Service and optimization, net. For the three and twelve months ended March 31, 2026, Fee-for-Service revenue was 82% and 81% of total revenue, respectively, while the remaining 18% and 19%, respectively, of revenue was derived from our optimization strategies. Total revenues in the three and twelve months ended March 31, 2026 were \$124.9 million and \$479.4 million, respectively, compared to \$128.1 million and \$415.3 million in the three and twelve months ended March 31, 2025, respectively.

Fee-for-Service revenue decreased by \$6.4 million, or 6%, in the three months ended March 31, 2026 compared to the three months ended March 31, 2025. Fee-for-Service revenue increased by \$21.7 million, or 6%, in the twelve months ended March 31, 2026 compared to the twelve months ended March 31, 2025. In each case the changes in Take-or-Pay and STS revenues are outlined below.

ToP revenues increased compared to the prior periods due to higher fees per unit of storage capacity contracted and higher contracted capacity. Weighted average ToP contract fees were approximately \$2.32 per decatherm (“Dth”) for both the three and twelve months ended March 31, 2026, a 25% increase compared to \$1.86 per Dth for both the three and twelve months ended March 31, 2025. Effective working gas storage capacity allocated to ToP contracts for the fiscal 2026 year increased by 3% to 98.6 million Dth.

STS revenues decreased by \$18.6 million, or 30% for the three months ended March 31, 2026 compared to the same period in the prior year. STS revenues decreased by \$26.9 million, or 15% for the twelve months ended March 31, 2026 compared to the same period in the prior year. As related to each change, the winter prior to the start of fiscal 2025 was relatively warm which caused injection season natural gas prices to fall in that year. However, there was not a corresponding decrease to forward winter prices. As a result, seasonal price spreads were relatively strong in fiscal 2025 resulting in relatively higher STS revenues across the year.

*Optimization, net*

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
<b>Optimization, net</b>	\$ 21.9	\$ 18.7	\$ 90.9	\$ 48.5
Realized optimization, net	29.3	30.0	78.8	56.6
Unrealized optimization (losses) gains, net	(7.4)	(11.3)	12.1	(8.1)

Realized optimization, net is generated from the purchase of natural gas inventory and its forward sale to future periods through financial energy trading contracts. Our facilities are used to store the inventory between the purchase and physical sale of the natural gas. When evaluating the performance of our optimization business, we focus on our realized optimization margins, including the impact of inventory adjustments, if any, but excluding the impact of unrealized economic hedging gains and losses. For financial reporting purposes, our revenue includes the impact of unrealized economic hedging gains and losses which cause our reported optimization, net to fluctuate from period to period.

Realized optimization, net decreased by \$0.7 million, or 2% in the three months ended March 31, 2026 compared to the three months ended March 31, 2025. While our storage optimization revenues increased \$3.0 million compared to the prior three month period, the increases were offset by weaker retail operating margins, which resulted in our net retail optimization revenues declining by \$3.7 million.

Realized optimization, net increased by \$22.2 million, or 39% in the twelve months ended March 31, 2026, compared to the twelve months ended March 31, 2025. The combination of a decrease in capacity used by STS activities, as well as lower natural gas prices allowed more capacity to be utilized by optimization activities.

The following table sets forth the revenues, net earnings and net earnings from continuing operations of the Business for each of the three most recently completed fiscal years:

(in millions, USD)	Fiscal Years Ended March 31,		
	2026	2025	2024
Total revenues	\$ 479.4	\$ 415.3	\$ 348.6
Net earnings	206.9	209.4	253.9
Net earnings from continuing operations	206.9	209.4	138.6

The increase in revenues in fiscal 2026 compared to 2025 was primarily due to higher ToP revenues, mainly related to our California facilities. Demand for storage services in California increased as customers sought natural gas price stability in a region that is a net importer of natural gas and increasingly powered by intermittent renewable power generation, with natural gas serving as a backup power source. To a lesser extent, ToP revenues also increased in Alberta, which was primarily attributable to our customers seeking natural gas price and supply stability in an increasingly volatile and tight market.

The increase in fiscal 2025 compared to 2024 was primarily driven by realizing wider seasonal spreads in our STS contracting across our Alberta-based facilities. In particular, fiscal 2025 summer natural gas prices were lower due to relatively high levels of natural gas in storage during the injection season while winter prices remained elevated. To a lesser extent, the increase was also influenced by higher ToP revenues in California, for which the reason was substantially the same as noted above for the fiscal 2026 increase versus fiscal 2025.

The Business' net earnings were impacted by the factors outlined in *Results of Operations and Financial Results of the Business*, including the changes in revenues noted directly above. The positive impact of increased revenues in fiscal 2026 was offset mainly by costs incurred related to the Legacy Incentive Plans. Increased fiscal 2025 earnings from continuing operations were largely due to the noted change in revenues. Fiscal 2024 net earnings were impacted by the sale of interests in the Tres Palacios and Salt Plains gas storage facilities, which accounted for \$115.3 million of net earnings in that year. This impact was attributable to a net gain on the sale of those facilities of \$114.7 million and to \$0.6 million in residual income from the related discontinued operations.

### Expenses

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
Cost of gas storage services	\$ 3.6	\$ 5.2	\$ 8.2	\$ 11.0
Operating	13.2	13.8	50.8	49.5
General and administrative	6.5	7.8	22.2	24.2
Depreciation and amortization	7.7	7.7	34.1	33.1
Financing costs	16.2	29.7	89.8	93.1
(Gain) loss on gas storage obligations, net	(1.4)	0.3	(4.5)	(1.3)
Other expenses	52.4	1.7	55.3	6.9

Cost of gas storage services decreased by \$1.6 million, or 31%, and \$2.8 million, or 25%, for the three and twelve months ended March 31, 2026, respectively, compared to the three and twelve months ended March 31, 2025 due to changes in natural gas prices resulting in lower costs of procuring pressure support gas for injection and withdrawal activities.

Operating expenses decreased by \$0.6 million, or 4%, in the three months ended March 31, 2026 compared to the three months ended March 31, 2025. The decrease was mainly the result of a relatively warm winter during the three months ended March 31, 2026, which reduced our fuel and electricity expenses as well as maintenance and general operating costs. The decreases were offset to some extent by higher land rental and property tax costs. Operating expenses increased by \$1.3 million, or 3%, in the twelve months ended March 31, 2026, compared to the twelve months ended March 31, 2025. The change was mainly the result of higher land rental and property tax costs, driven primarily by increased revenues. These costs were offset to some extent by reduced fuel, electricity and general operating costs resulting from a relatively warm winter during fiscal 2026.

General and administrative costs decreased by \$1.3 million, or 17%, for the three months ended March 31, 2026 compared to the same period in the prior year. General and administrative costs decreased by \$2.0 million, or 8%, for the twelve months ended March 31, 2026 compared to the twelve months ended March 31, 2025. In each case, incentive compensation costs were lower in the current year period primarily as a result of a shift from shorter-term cash incentive compensation to longer-term share-based incentive compensation. The decrease in compensation costs was offset to some extent in each comparative period by increased compliance costs related to new public reporting requirements, including increased audit, legal and information technology costs.

Depreciation and amortization expense was unchanged for the three months ended March 31, 2026 in comparison to the three months ended March 31, 2025. Depreciation and amortization expense increased by \$1.0 million, or 3%, in the twelve months ended March 31, 2026 compared to the twelve months ended March 31, 2025, due mainly to capacity optimization capital projects at our Wild Goose facility whereby three new wells were put into service in late fiscal 2025.

Financing costs decreased by \$13.5 million, or 45%, in the three months ended March 31, 2026 compared to the three months ended March 31, 2025. Excluding a \$10.8 million increase in unrealized gains on our interest rate hedges, financing costs decreased by \$2.7 million. This remaining decrease was primarily due to reduced interest incurred on our Term Loan due 2031 resulting from March 2025 and October 2025 repricing transactions, which reduced the associated interest rates on the loan facility. Financing costs decreased by \$3.3 million, or 4%, for the twelve months ended March 31, 2026, compared to the twelve months ended March 31, 2025. Excluding a \$5.4 million increase in unrealized gains on our interest rate hedges, financing costs increased by \$2.1 million. This increase was principally due to lower interest earnings on cash balances held as fiscal 2026 saw more frequent distributions of surplus cash compared to fiscal 2025. The impact of a higher level of total debt outstanding following the issue of the \$1,250.0 million Term Loan due 2031 was largely offset by relatively lower interest rates on that facility.

(Gain) loss on gas storage obligations, net changed from a loss of \$0.3 million to a gain of \$1.4 million for the three months ended March 31, 2025 and 2026, respectively, and the gain increased by \$3.2 million for the twelve months ended March 31, 2026 compared to the twelve months ended March 31, 2025. In each case the change was caused by mark-to-market fluctuations resulting from changes in the natural gas market prices underlying the related hybrid financial liability.

Other expenses increased by \$50.7 million and \$48.4 million in the three and twelve months ended March 31, 2026, respectively, compared to the three and twelve months ended March 31, 2025. The changes were principally due to compensation costs incurred as related to the Legacy Incentive Plans, see “Notable Transactions”. During the three months ended March 31, 2026, aggregate payments related to these plans totaling \$51.5 million were incurred and made to certain officers, employees and former employees. The payments were funded by an equivalent cash capital contribution from Brookfield. As the costs of these plans were not related to ordinary course operations, they have been classified as other expenses.

*Income tax expense (benefit), net*

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
Income tax expense (benefit)	\$ 2.3	\$ 4.9	\$ 16.6	\$ (10.6)

Income tax expense decreased by \$2.6 million, or 53%, for three months ended March 31, 2026, compared to the three months ended March 31, 2025. The decrease was primarily the result of costs incurred on the Legacy Incentive Plans during the current year quarter, which increased our costs relative to the comparative period.

Income tax expense for the twelve months ended March 31, 2026 was \$16.6 million compared to a recovery of \$10.6 million for the twelve months ended March 31, 2025, for a total increase in tax charges of \$27.2 million. The recovery in the prior period was primarily the result of a tax benefit recognized from the settlement of loans that were subject to a deferred gain on debt in the historical period. The Business incurred \$5.5 million in additional current tax expenses in the twelve months ended March 31, 2026 compared to the prior fiscal year due to the Business exhausting certain non-capital loss tax pools during the third fiscal quarter.

**Statements of Financial Position of the Business**

The following table summarizes the statements of financial position of the Business as at March 31, 2026, 2025 and 2024:

(in millions, USD)	As at March 31,		
	2026	2025	2024
Total assets	\$ 1,239.7	\$ 1,430.2	\$ 1,331.0
Property, plant and equipment, net	888.1	884.6	881.5
Long-term debt	1,197.3	1,208.1	464.7
Total long-term liabilities	1,398.6	1,403.1	892.7
Equity	(238.8)	(85.8)	335.5

Total assets were \$1,239.7 million at March 31, 2026, compared to \$1,430.2 million at March 31, 2025. The \$190.5 million decrease is primarily attributed to a \$161.8 million decrease in cash held. Cash generated from operations during fiscal 2025 was held until the first quarter of fiscal 2026, before being distributed to Brookfield in May 2025. Similar accumulations of cash did not occur in fiscal 2026 due to cash distributions being made on a more frequent basis. Furthering the decrease was an \$83.0 million reduction in amounts receivable from related parties. The amount was settled by non-cash distributions during fiscal 2026. The above decreases were offset to some extent by increased inventories held as of March 31, 2026, largely due to a relatively warm winter allowing the Company to realize financial gains on economic hedges and re-hedge physical inventories to future periods.

Total assets were \$1,430.2 million at March 31, 2025, compared to \$1,331.0 million at March 31, 2024. The increase is attributed to an increase in cash, amounts due from affiliates, capital additions during the period and timing of contractual receivables, partially offset by lower natural gas inventory and risk management assets.

Property, plant and equipment, net increased from \$884.6 million at March 31, 2025 to \$888.1 million at March 31, 2026. The \$3.5 million increase was due to a combination of capital additions related to regulatory driven capital spending requirements in California and right-of-use asset additions due to the modification of certain leases in California, which included the elimination of certain variable lease payments in favor of a fixed payment lease.

During fiscal 2025, property, plant and equipment, net increased from \$881.5 million to \$884.6 million primarily due to capital additions related to the drilling and tie-in of three new performance-enhancing storage wells at Wild Goose, partially offset by depreciation expense.

Long-term debt decreased to \$1,197.3 million at March 31, 2026, compared to \$1,208.1 million at March 31, 2025. The decrease is due to mandatory principal repayments required on the Term Loan due 2031, partially offset by the unwinding of deferred financing costs.

Long-term debt increased to \$1,208.1 million at March 31, 2025, compared to \$464.7 million at March 31, 2024. The increase is primarily attributed to successfully recapitalizing our Business with the Term Loan due 2031, partially offset by the repayment of the Term Loan due 2026 and all remaining outstanding Brookfield debt, including accrued interest, in the amount of \$233.5 million. The remaining proceeds were used to fund a \$455.2 million distribution to Brookfield, an advance of \$83.0 million to Brookfield as well as transaction fees related to the refinancing.

Total long-term liabilities decreased to \$1,398.6 million as of March 31, 2026 from \$1,403.1 million as of March 31, 2025. The decrease was attributable to the payments made on our debt and lease obligations, which were partially offset by increased deferred tax liabilities which was largely due to the Business exhausting certain tax pools.

Total long-term liabilities increased to \$1,403.1 million as of March 31, 2025 from \$892.7 million as of March 31, 2024. The increase was primarily attributable to changes noted above for long-term debt.

Equity changed to a deficit of \$238.8 million as of March 31, 2026 from a deficit of \$85.8 million as of March 31, 2025. The decline was primarily due to the Business distributing excess cash held at March 31, 2025 to owners during fiscal 2026.

Equity changed to a deficit \$85.8 million as of March 31, 2025 from a surplus of \$335.5 million as of March 31, 2024, primarily as a result of distributions made related to the recapitalization of the Business noted for long-term debt above.

## Results of Operations, Financial Results and Financial Position of Rockpoint Gas Storage Inc.

### Results of Operations

The following table sets forth the results of operations of Rockpoint Gas Storage Inc. for the three months ended March 31, 2026 and for the period beginning July 28, 2025 and ended March 31, 2026:

(in millions, USD)	<b>Three Months Ended March 31, 2026</b>	<b>July 28, 2025 to March 31, 2026</b>
<b>INCOME (EXPENSES)</b>		
Share of income from equity accounted investees	\$ 4.4	\$ 31.9
General and administrative	(0.6)	(1.3)
Foreign exchange gains	—	3.4
Other expenses	(1.0)	(1.0)
<b>EARNINGS BEFORE INCOME TAXES</b>	<b>2.8</b>	<b>33.0</b>
Income tax (benefit) expense		
Current	(0.7)	(0.1)
Deferred	2.1	6.6
<b>NET EARNINGS</b>	<b>\$ 1.4</b>	<b>\$ 26.5</b>

On October 15, 2025, the Company completed its acquisition of a 40% interest in the Business, see “Notable Transactions”. Prior to this date, the Company did not have any significant assets or liabilities and had not entered into any material transactions.

Weighted average earnings per Class A Share of the Company, expressed in dollars, both on a basic and diluted earnings basis for the inaugural fiscal period of July 28, 2025 to March 31, 2026 were \$0.73. For the quarters ended March 31, 2026 and December 31, 2025, Earnings per Class A Share, both basic and diluted, were \$0.03 and \$0.56, respectively. The Company was effectively dormant for the period beginning July 28, 2025 until September 30, 2025.

#### *Share of income from equity accounted investees*

The share of income from equity accounted investees includes net earnings generated from the Company’s investment in the Business. There was \$4.4 million and \$31.9 million in income recognized for the three months ended March 31, 2026 and for the period beginning July 28, 2025 and ended March 31, 2026, respectively, which represents a 40% share of the net earnings generated from the Business since the acquisition on October 15, 2025. As part of the equity income calculation, the earnings of the Business were adjusted to account for certain underlying fair value differences that existed on the day of the investment acquisition.

The share of income from equity accounted investees was impacted by the costs incurred for the Legacy Incentive Plans within the Business during the three months ended March 31, 2026. As a result of these costs, equity earnings declined by \$20.6 million, or 40% of the total \$51.5 million legacy incentive plan costs recorded in the Business.

#### *General and administrative*

General and administrative costs include management fees charged from a subsidiary of Swan OpCo for certain corporate services, costs of Board of Director compensation and various administrative expenses.

#### *Foreign exchange gains*

The \$3.4 million in foreign exchange gains for the period beginning July 28, 2025 and ended March 31, 2026 arose primarily as a result of the settlement of a payable to Brookfield for the purchase of the 40% interest in the Business. The payable was denominated in U.S. dollars but ultimately paid using Canadian dollars raised from the Offering.

### *Income tax (benefit) expense*

Current tax was a \$0.1 million benefit for the period beginning July 28, 2025 and ended March 31, 2026. Deductible cost pools, mainly related to the property, plant and equipment contained within flow-through entities for which the Company has investments in, offset the accumulation of current taxes in the period. The deferred tax expense of \$6.6 million for the period beginning July 28, 2025 and ended March 31, 2026 was primarily the result of temporary differences arising between the tax and accounting basis of property, plant and equipment contained within flow-through tax entities of the Business.

### *Assets and Liabilities*

Rockpoint's primary asset is its investment in the Business which, as of March 31, 2026, had a carrying value of \$900.9 million. The investment amount represents the historical costs of acquisition of \$892.2 million transacted on October 15, 2025, which included \$504.6 million in cash consideration paid, \$377.4 million in shares issued and \$10.2 million related to initial deferred tax liabilities recognized, plus a share of net income and other comprehensive earnings since that date totaling \$32.1 million, offset by distributions received to date totaling \$23.4 million.

As of March 31, 2026, the Company also had under its control \$14.8 million in cash withheld for tax purposes on behalf of certain Brookfield affiliates related to the purchase of the Business. The amount held was fully offset by a related party obligation to release the cash once clearances from tax authorities are received. Subsequent to March 31, 2026, final clearances were received and all restricted funds were released.

The Company was incorporated on July 28, 2025, with negligible assets and liabilities. As of March 31, 2026, the Company had total assets and total long-term liabilities with carrying values of \$916.3 million and \$16.8 million, respectively.

### **Non-IFRS Measures Utilized by Our Business**

We report our financial results in accordance with IFRS. However, management believes that certain non-IFRS financial measures provide investors with useful information in evaluating our performance. Management believes that excluding certain items that may vary substantially in frequency and magnitude period-to-period from net earnings provides useful supplemental measures that assist in evaluating our ability to generate earnings and cash flow, and more readily compare these metrics between past and future periods. These non-IFRS financial measures are not standardized measures under IFRS and may not be comparable to similarly titled measures used by other companies.

Our non-IFRS financial measures should not be considered in isolation from, or as substitutes for, financial information prepared in accordance with IFRS. There are several limitations related to the use of our non-IFRS financial measures as compared to the closest comparable IFRS measures. Some of these limitations include:

- the exclusion of some, but not all, items that affect net earnings and comprehensive earnings;
- not allowing us to analyze the effect of certain recurring and non-recurring items that materially affect our net earnings and comprehensive earnings;
- not reflecting all cash expenditures, or future requirements, for capital expenditures or contractual commitments; and
- other companies within the industry may calculate the non-IFRS measures differently than we do, limiting its usefulness as a comparative measure.

### *Non-IFRS Financial Measures and Ratios*

Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt are non-IFRS financial measures and ratios and are used by our management and by external users of our financial statements, such as investors, research analysts and others, to assess the financial performance of our assets over the long-term to generate sufficient cash to service indebtedness, fund maintenance and growth capital projects and to make distributions to our shareholders. In addition, Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt are frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry with similar capital structures. We use Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt to supplement IFRS financial measures of performance to evaluate the effectiveness of our business strategies, to make budgeting decisions and to compare our performance against that of other peer companies using similar measures.

### *Adjusted EBITDA*

We define Adjusted EBITDA, which we use as the primary non-IFRS financial measure of profitability to evaluate the performance of our Business, as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), and other (income) expenses.

We believe that Adjusted EBITDA is meaningful because it presents the financial performance of our Business on a basis which excludes the impact of certain non-cash items, items whose impact is external to ordinary course operations, extraordinary items, as well as how the operations have been financed.

Adjusted EBITDA when expressed as a percentage of Adjusted Gross Margin, as defined below, (“Adjusted EBITDA Margin”) is a non-IFRS ratio calculated as Adjusted EBITDA divided by Adjusted Gross Margin. Adjusted EBITDA Margin is used by our management and by external investors to assess efficiency in managing operating and general and administrative expenses relative to our Adjusted Gross Margin.

### *Adjusted Gross Margin*

We define Adjusted Gross Margin, which we use as a non-IFRS financial measure of profitability, as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), other (income) expenses, operating, general and administrative expenses and other items.

We believe that Adjusted Gross Margin is a useful measure of profitability because it presents our residual earnings after deducting the direct costs of gas storage services from our Fee-for-Service and realized optimization revenue.

Fee-for-Service gross margin, which is net of cost of gas storage services, as a percentage of Adjusted Gross Margin is a non-IFRS ratio and is calculated as Fee-for-Service gross margin divided by Adjusted Gross Margin. Fee-for-Service gross margin as a percentage of Adjusted Gross Margin is used by our management and by external investors to determine the proportion of Adjusted Gross Margin that is driven by Fee-for-Service gross margin.

### *Distributable Cash Flow*

In addition to Adjusted EBITDA and Adjusted Gross Margin, we utilize Distributable Cash Flow as a non-IFRS financial measure of profitability to provide insights into the cash earnings that are available for distribution, to buy back shares, fund working capital requirements, and/or reinvest in our Business to further enhance growth. We define Distributable Cash Flow as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), other (income) expenses, interest expense, mandatory debt repayments, current taxes, cash lease payments, maintenance capital expenditures and other items.

We believe that Distributable Cash Flow is a meaningful financial metric because it presents our cash earnings that are available for distribution, to buy back shares, and/or reinvest in our Business.

### *Net Debt*

Net debt is a non-IFRS financial measure used by management to assess the credit profile of our Business. Net debt is defined as total debt outstanding adjusted by unamortized discount and deferred financing costs and cash and cash equivalents.

Net debt when expressed as a multiple of Adjusted EBITDA is a non-IFRS ratio calculated by dividing net debt by Adjusted EBITDA. Net debt to Adjusted EBITDA is used by our management and by external investors to assess our ability to service our debt obligations.

The following table sets forth a reconciliation of Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow to net earnings of the Business, the most directly comparable IFRS financial measure for the periods indicated.

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
<b>Net earnings</b>	\$ 24.4	\$ 57.0	\$ 206.9	\$ 209.4
Add (deduct):				
Financing costs	16.2	29.7	89.8	93.1
Income tax expense (benefit)	2.3	4.9	16.6	(10.6)
Depreciation and amortization	7.7	7.7	34.1	33.1
Unrealized risk management losses (gains) <sup>(1)</sup>	6.2	11.7	(16.8)	6.9
Other expenses	52.4	1.7	55.3	6.9
<b>Adjusted EBITDA</b>	<b>109.2</b>	<b>112.7</b>	<b>385.9</b>	<b>338.8</b>
Operating	13.2	13.8	50.8	49.5
General and administrative	6.5	7.8	22.2	24.2
Other items <sup>(2)</sup>	(0.2)	(0.1)	0.2	(0.1)
<b>Adjusted Gross Margin</b>	<b>128.7</b>	<b>134.2</b>	<b>459.1</b>	<b>412.4</b>
Operating	(13.2)	(13.8)	(50.8)	(49.5)
General and administrative	(6.5)	(7.8)	(22.2)	(24.2)
Interest expense <sup>(3)</sup>	(18.6)	(22.7)	(80.7)	(70.0)
Mandatory debt repayments	(3.1)	(3.1)	(12.5)	(3.1)
Current taxes	(3.0)	—	(6.1)	(0.6)
Cash lease payments <sup>(4)</sup>	(3.4)	(3.1)	(8.6)	(9.3)
Maintenance capital expenditures <sup>(5)</sup>	(6.3)	(5.8)	(26.4)	(21.3)
Other items <sup>(2)</sup>	0.2	0.1	(0.2)	0.1
<b>Distributable Cash Flow</b>	<b>\$ 74.8</b>	<b>\$ 78.0</b>	<b>\$ 251.6</b>	<b>\$ 234.5</b>

**Notes:**

1. Excludes the net unrealized impact from interest rate swaps, which are included within financing costs.
2. Other items consists of net unrealized electricity contract gains/losses.
3. Interest expense includes interest on non-affiliated debt obligations, including the Term Loan due 2026, Term Loan due 2031, the ABL Facility, the Warwick Credit Facility and other interest income (expense), net of realized gains on interest rate swaps.
4. Excludes a one-time payment of \$19.3 million made during the three months ended September 30, 2025 related to modified storage leases. All future payments for the related leases were eliminated in exchange for one upfront payment. Excludes variable lease payments included in operating.
5. Fiscal 2025 maintenance capital expenditures were adjusted downwards to reflect \$5.5 million in one-time costs associated with historical heat imbalances and cushion gas migration.

The following table presents a reconciliation of the Business' net debt to total debt outstanding, the most directly comparable IFRS financial measure for the periods indicated:

(in millions, USD)	As at March 31,	
	2026	2025
Short-term debt	\$ 12.2	\$ 25.8
Long-term debt	1,197.3	1,208.1
Total debt outstanding	1,209.5	1,233.9
Add: Unamortized discount and deferred financing costs	24.9	26.5
Less: Cash and cash equivalents	(42.3)	(204.1)
<b>Net debt</b>	<b>\$ 1,192.1</b>	<b>\$ 1,056.3</b>
<b>Net debt to Adjusted EBITDA</b>	<b>3.1x</b>	<b>3.1x</b>

## Supplementary Financial Measures Utilized by Our Business

### *Contracted Fee-for-Service Revenue Backlog*

Contracted Fee-for-Service revenue backlog is a supplementary financial measure that represents the cumulative contracted revenues for our ToP and STS services, not yet recognized as revenue in the Financial Statements of the Business. Contracted Fee-for-Service revenue backlog is an operating measure that we use to evaluate the effectiveness of our contracting strategies and the stability of cash flow generation in the coming years.

The following table outlines the changes in our California contracted Fee-for-Service revenue backlog for fiscal 2026 and fiscal 2025:

(in millions, USD)	Fiscal Years Ended March 31,	
	2026	2025
<b>Opening balance</b>	\$ 737.7	\$ 452.0
Fee-for-Service contracts signed during the fiscal period	307.6	521.5
Fee-for-Service contracted backlog recognized in revenue	(260.9)	(235.8)
<b>Ending balance</b>	<u>\$ 784.4</u>	<u>\$ 737.7</u>

**Note:**

- Contracted Fee-for-Service revenue backlog excludes fuel and commodity recovery associated with ToP contracts.

As of March 31, 2026, contracted Fee-for-Service revenue backlog at our California facilities was \$784.4 million compared to \$737.7 million as of the end of fiscal 2025. Fee-for-Service contracts signed in fiscal 2026 contributed \$307.6 million to the backlog due to signing longer term ToP contracts at improved demand charges. This increase was partially offset by \$260.9 million of contracted Fee-for-Service revenue recognized in the period.

The following table outlines the changes in our Alberta contracted Fee-for-Service revenue backlog for fiscal 2026 and fiscal 2025:

(in millions, USD)	Fiscal Years Ended March 31,	
	2026	2025
<b>Opening balance</b>	\$ 155.5	\$ 115.6
Fee-for-Service contracts signed during the fiscal period	125.7	166.5
Fee-for-Service contracted backlog recognized in revenue	(121.7)	(124.6)
Foreign currency adjustments and other	3.2	(2.0)
<b>Ending balance</b>	<u>\$ 162.7</u>	<u>\$ 155.5</u>

**Note:**

- Contracted Fee-for-Service revenue backlog excludes fuel and commodity recovery associated with ToP contracts.

As of March 31, 2026, contracted Fee-for-Service revenue backlog at our Alberta facilities was \$162.7 million compared to \$155.5 million as of the end of fiscal 2025. Fee-for-Service contracts added \$125.7 million to the backlog in fiscal 2026. This increase was offset by \$121.7 million of contracted Fee-for-Service revenue recognized in the period.

The weighted average remaining contract life of all ToP contracts across the portfolio was 3.5 years as of March 31, 2026 (March 31, 2025 - 3.5 years).

### *Analysis of Key Financial and Operating Measures*

The following section contains a discussion of key financial and operating measures utilized in managing our Business, including for performance measurement, capital allocation and valuation purposes.

#### *Take-or-Pay Contracted Storage Rates*

ToP contracted storage rates refers to the weighted average demand charge paid by our long-term firm storage service contract customers. Under these arrangements, our customers are obligated to pay us a fixed monthly demand charge for storage capacity regardless of utilization, resulting in steady, stable cash flow generation. ToP contracted storage rates are primarily driven by the expected summer to winter seasonal differences in gas prices over the term of the contract, combined with the value a customer places on our ability to deliver the stored gas reliably and quickly for their own use.

#### *Short-term Storage Contract Rates*

Under STS contract arrangements, which typically span up to one storage season, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas. Similar to ToP contracted storage rates, STS contract rates are primarily driven by the difference in future gas prices between when it is stored and when it will be withdrawn, and our ability to deliver the stored gas reliably and on time.

ToP and STS contracts are referred to on a combined basis as "Fee-for-Service" contracts.

The following table provides information regarding our ToP and STS contracts for fiscal 2026 and fiscal 2025.

	Fiscal 2026			Fiscal 2025		
	Contract Rate (\$/Dth <sup>(1)</sup> )	Working Gas Capacity Contribution (MMDth)	Fee-for-Service Gross Margin (in millions of \$)	Contract Rate (\$/Dth <sup>(1)</sup> )	Working Gas Capacity Contribution (MMDth)	Fee-for-Service Gross Margin (in millions of \$)
<b>ToP Contracts</b>						
California	2.93	70.0	204.9	\$ 2.37	68.9	163.3
Alberta	1.00	28.6	28.7	0.80	27.2	21.7
			<u>233.6</u>			<u>185.0</u>
<b>STS Contracts<sup>(2)</sup></b>						
California			57.4			69.5
Alberta			89.3			101.3
			<u>146.7</u>			<u>170.8</u>

#### **Notes:**

1. Fiscal 2026 ToP contracted demand charges, excluding fuel and commodity recovery, were \$2.87/Dth and \$0.95/Dth for California and Alberta facilities, respectively (fiscal 2025 - \$2.30/Dth and \$0.75/Dth, respectively).
2. Net of cost of gas storage services.

*Supplementary Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow*

The following table outlines the Business' Adjusted Gross Margin, Adjusted EBITDA and Distributable Cash Flow for the three and twelve months ended March 31, 2026 and 2025.

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
Fee-for-Service gross margin				
ToP	\$ 58.7	\$ 46.5	\$ 233.6	\$ 185.0
STS, net of cost of gas storage services	40.7	57.7	146.7	170.8
Total Fee-for-Service gross margin	99.4	104.2	380.3	355.8
Realized optimization, net	29.3	30.0	78.8	56.6
<b>Adjusted Gross Margin</b>	<b>128.7</b>	<b>134.2</b>	<b>459.1</b>	<b>412.4</b>
Operating, general and administrative expense and other	(19.5)	(21.5)	(73.2)	(73.6)
<b>Adjusted EBITDA</b>	<b>\$ 109.2</b>	<b>\$ 112.7</b>	<b>\$ 385.9</b>	<b>\$ 338.8</b>
<b>Distributable Cash Flow</b>	<b>\$ 74.8</b>	<b>\$ 78.0</b>	<b>\$ 251.6</b>	<b>\$ 234.5</b>
Fee-for-Service as a % of Adjusted Gross Margin	77%	78%	83%	86%
Adjusted EBITDA Margin	85%	84%	84%	82%

The changes in Adjusted Gross Margin are for substantially the same reasons as those outlined in the *Fee-for-Service revenue* and *Optimization, net* sections of this report.

Adjusted EBITDA decreased by \$3.5 million, or 3%, for the three months ended March 31, 2026 compared to the three months ended March 31, 2025. The decline was primarily due to differences in weather across the comparative periods. The current year quarter saw relatively mild winter weather and, as a result, there were relatively fewer opportunities to earn STS revenues whereas the prior year quarter saw periods of cold weather, which created incremental opportunities.

Adjusted EBITDA increased by \$47.1 million, or 14%, for the twelve months ended March 31, 2026 compared to the same period in the prior fiscal year. The increase was primarily the result of an increase in ToP contract revenue at our California facilities. Demand for storage services remained strong in California as our customers utilized natural gas storage services to provide price stability and energy reliability in a state that is a net importer of natural gas and increasingly powered by intermittent renewable power generation.

Distributable Cash Flow decreased by \$3.2 million, or 4%, for the three months ended March 31, 2026 compared to the three months ended March 31, 2025. The primary reason for the decrease was the increased current tax expense which was the result of the Business exhausting certain non-capital loss tax pools during the third quarter of fiscal 2026.

Distributable Cash Flow increased by \$17.1 million, or 7%, for the twelve months ended March 31, 2026, compared to the twelve months ended March 31, 2025, which was primarily the result of increased realized revenues. The increase was offset to some extent by increased interest costs on non-affiliated debt and the addition of quarterly mandatory debt repayments as a result of the \$1,250.0 million Term Loan due 2031.

## Quarterly Results Summary

The following table presents quarterly information for the Business:

(in millions, USD)	Fiscal 2026				Fiscal 2025			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	\$ 124.9	\$ 147.2	\$ 103.2	\$ 104.1	\$ 128.1	\$ 112.4	\$ 83.1	\$ 91.7
Net earnings	24.4	88.4	45.8	48.3	57.0	58.1	48.7	45.6
Adjusted EBITDA	109.2	116.4	83.2	77.1	112.7	96.6	65.5	64.0
Adjusted Gross Margin	128.7	133.3	101.3	95.8	134.2	113.0	82.8	82.4
Distributable Cash Flow	74.8	82.2	48.0	46.6	78.0	61.5	45.3	49.7

For information detailing the reasons for certain movements in the items noted, see “Results of Operations and Financial Results of the Business” as well as “Non-IFRS Measures Utilized by Our Business - Supplementary Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow”.

Results of the Business are influenced by seasonal factors. See “Business Overview - Seasonality of the Business”.

In addition to factors noted above, our quarterly results were mainly influenced by (i) as related to all categories noted, increasing contract rates on our ToP revenue stream due to continued strengthening of storage market conditions; (ii) as related to net earnings, costs incurred under the Legacy Incentive Plans in the fourth quarter of fiscal 2026; and (iii) as related to distributable cash flow, the issuance of the Term Loan due 2031 in September 2024, which increased non-affiliated interest costs and the addition of mandatory debt repayments, as well as the increase in current tax expense which was the result of the Business exhausting certain non-capital loss tax pools during the third quarter of fiscal 2026.

## Liquidity and Capital Resources

### Sources of Liquidity

The following table presents the combined available liquidity for the Business and the Company:

(in millions, USD)	As at March 31,	
	2026	2025
Cash and cash equivalents <sup>(1)</sup>	\$ 42.3	\$ 204.1
Undrawn and available committed credit facilities <sup>(2)</sup>	318.9	112.7
<b>Total available liquidity</b>	<b>\$ 361.2</b>	<b>\$ 316.8</b>

#### Note:

1. Excludes restricted cash.
2. March 31, 2025 excludes the ABL Facility borrowing base attributable to cash on hand.

As of March 31, 2026, we had \$361.2 million of available liquidity, which was comprised of \$42.3 million of available cash and cash equivalents and \$318.9 million of undrawn and available capacity on the Revolving Credit Facility. Our total available liquidity was \$44.4 million higher at the end of fiscal 2026 compared to the end of fiscal 2025, which is attributed to the replacement of the ABL Facility with the Revolving Credit Facility. Unlike the ABL Facility, which required the maintenance of certain assets to support the borrowing capacity, the Revolving Credit Facility has a set limit, inclusive of amounts that may be dedicated to letter of credits that we may issue.

The portion of liquidity comprised of cash fell by \$161.8 million, which is primarily attributed to distributions to owners made during fiscal 2026.

Our Business has few non-discretionary capital requirements and generates strong free-cash flows from operations. Our largest normal course capital requirements are principal and interest payments on our debt facilities and capital expenditures to maintain the operating performance of our storage assets.

We expect our cash generated from operations and available capacity under our available credit facilities to be sufficient to meet our future cash requirements. These requirements include changes in working capital, debt service obligations, anticipated capital expenditures, dividend payments, and cash lease payments.

On October 15, 2025 we obtained the Revolving Credit Facility to enhance liquidity and replace the then existing ABL Facility. The borrowers under the Revolving Credit Facility are Rockpoint and certain subsidiaries of Swan OpCo. The borrowings to date under the Revolving Credit Facility have all been made by the subsidiaries of Swan OpCo to fund the requirements of the Business, and we anticipate that most drawings will continue to be made by subsidiaries of Swan OpCo. The costs relating to borrowings of subsidiaries of Swan OpCo under the Revolving Credit Facility are borne by Rockpoint and Brookfield in proportion to their respective ownership interests in Swan OpCo and the Business. Rockpoint expects that its future separate borrowings under the Revolving Credit Facility used to service stand-alone administrative expenditures and requirements will be relatively minimal.

The Revolving Credit Facility has an aggregate commitment available of \$350.0 million, including a letters of credit sub-limit of \$175.0 million, and matures on October 15, 2030. Revolving Credit Facility drawings are available in U.S. dollars and Canadian dollars, and subject to lender consent, we can request additional currencies. The Revolving Credit Facility bears interest at a floating rate, which for U.S. dollars, can be either base rate or SOFR, and for Canadian dollars, can be any of term Canadian overnight repo rate average (“CORRA”), Canadian prime rate and daily compound CORRA, with interest accruing at the applicable benchmark plus an applicable margin determined by a pricing grid based on Rockpoint Gas Storage Partners LP’s (or Rockpoint’s) corporate credit rating. Customary commitment and letter of credit fees are payable under the Revolving Credit Facility.

On October 15, 2025, initial drawings of \$55.0 million on the Revolving Credit Facility, as well as cash on hand, were used to repay the then outstanding \$55.8 million cash drawings on the ABL Facility. On the same day, issued letters of credit then amounting to \$37.2 million were also transferred from the ABL Facility to the Revolving Credit Facility. Immediately after these transfers, the Business entered into a termination agreement with the ABL Facility agent and all such obligations under that facility were discharged. The Revolving Credit Facility is currently used to issue letters of credit, and to support working capital, capital expenditures and other general corporate purposes.

The Revolving Credit Facility agreement requires the maintenance of a ratio of consolidated total net debt to consolidated EBITDA (as defined in the Revolving Credit Facility agreement) of no more than 5.00 to 1.00, tested at the end of each fiscal quarter and beginning with the quarter ended December 31, 2025. At March 31, 2026, the Business and the Company were in compliance with all covenant requirements under the Revolving Credit Facility and there were no restrictions on our ability to borrow up to the total amount of liquidity available.

On October 14, 2025, AECO funded the repayment of the then outstanding \$9.4 million (C\$13.2 million) balance on the Warwick Credit Facility, which was a revolving credit agreement with a limit of C\$37.5 million. Subsequently, WGS LP received a release and discharge on the facility.

In relation to the Term Loan due 2031, the Business, in order to reduce its exposure to variable term SOFR interest rates, entered into interest rate swap contracts on October 24, 2025 which blended in the previous interest rate swaps that hedged \$900.0 million of principal until September 2026. The updated contracts locked in a blended 3.40% SOFR interest rate and, together with a subsequent re-pricing agreement discussed below, effectively a 5.90% all-in rate for SOFR denominated loans on the remaining projected principal borrowings, estimated then as the principal balance outstanding as of the date of the revised hedging transactions less mandatory principal repayments over the remaining term of the loan. All future borrowings are projected to be drawn using three-month SOFR terms.

Effective October 29, 2025, as permitted under the credit agreement governing the Term Loan due 2031 (the “Term Loan Credit Agreement”), the Business and its creditors repriced the Term Loan due 2031 to reduce the interest rate for SOFR loans from SOFR plus 3.00% to SOFR plus 2.50% and the interest rate for base rate loans from the bank’s applicable base rate plus 2.00% to the bank’s applicable base rate plus 1.50%.

Subsequent to the March 31, 2026 fiscal year end and effective May 7, 2026, as permitted under the Term Loan Credit Agreement, the Business, along with the Company and its lenders, repriced the Term Loan due 2031 to reduce the interest rate for SOFR loans from SOFR plus 2.50% to SOFR plus 2.25% and the interest rate for base rate loans from the bank’s applicable base rate plus 1.50% to the bank’s applicable base rate plus 1.25%. As a result, the all-in interest rate of the Term Loan due 2031 on SOFR drawn balances decreased to 5.65%. This latest repricing is expected to reduce the Business’ annual interest costs by approximately \$3.0 million per year.

On the same date as the October 2025 repricing, we also entered into amendments to the Term Loan due 2031 that changed the excess cash flow prepayment conditions. Previously, if the outstanding principal borrowings of first lien debt, net of unrestricted cash, to Consolidated EBITDA (as defined in the Term Loan Credit Agreement) (the “First Lien Net Leverage Ratio”) was greater than 4.50 to 1.00 for a fiscal year, we were required, subject to certain other conditions, to prepay the Term Loan due 2031 with 75.0% of the excess cash flow above the greater of \$63.1 million or 25.0% of Consolidated EBITDA as defined in the Term Loan due 2031 agreement, with steps down to 50.0%, 25.0% and 0.0% of the excess cash flow if the First Lien Net Leverage Ratio is less than or equal to 4.50, 4.00 and 3.50 to 1.00, respectively, for such fiscal year. The amendments changed the conditions such that if the First Lien Net Leverage Ratio is greater than 4.50 to 1.00 for a fiscal year, we are required, subject to certain other conditions, to prepay the Term Loan due 2031 with 50.0% of the excess cash flow above the greater of \$63.1 million or 25.0% of Consolidated EBITDA as defined in the Term Loan due 2031 agreement, with steps down to 25.0% and 0.0% of the excess cash flow if the First Lien Net Leverage Ratio is less than or equal to 4.50 and 4.00 to 1.00, respectively. This change is not anticipated to have a material impact on cash flows related to the Term Loan due 2031 but provides more flexibility to the Business in managing its capital structure. As of March 31, 2026, no excess cash flow payments were required.

The Term Loan due 2031 requires the maintenance of a ratio of Consolidated EBITDA (as defined in the Term Loan Credit Agreement) to the sum of certain interest charges and scheduled principal payments, (the “Debt Service Coverage Ratio”) of at least 1.10 to 1.00, tested quarterly. Figures used to calculate Consolidated EBITDA and the Debt Service Coverage Ratio are derived from the Business. As of March 31, 2026, the Business and the Company were in compliance with all covenant requirements under the Term Loan due 2031.

### ***Cash Flows of the Business***

The following table summarizes our cash flows for the periods presented:

(in millions, USD)	Fiscal Years Ended March 31,	
	2026	2025
<b>Statements of Cash Flows Summary</b>		
<b>Operating activities:</b>		
Net earnings	\$ 206.9	\$ 209.4
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Deferred income tax expense (benefit)	10.5	(11.2)
Unrealized risk management (gains) losses	(25.0)	4.0
Depreciation and amortization	34.1	33.1
Amortization of deferred financing costs	7.4	6.8
Other	1.8	0.1
Changes in non-cash working capital	(45.6)	71.5
<b>Net cash provided by operating activities</b>	<b>190.1</b>	<b>313.7</b>
<b>Net cash used in investing activities</b>	<b>(32.9)</b>	<b>(34.9)</b>
<b>Net cash used in financing activities</b>	<b>(319.8)</b>	<b>(174.2)</b>

### *Net cash provided by operating activities*

Net cash provided by operating activities was \$190.1 million for the twelve months ended March 31, 2026 compared to \$313.7 million for the twelve months ended March 31, 2025. The \$123.6 million decrease was primarily due to the refilling of our proprietary natural gas inventories during fiscal 2026. A relatively warm winter prior to the start of the twelve months ended March 31, 2025 allowed us to carry over higher volumes of proprietary inventories into that period, consequently requiring less cash outflows to refill in fiscal 2025. To a lesser extent, changes in margining requirements, as a result of natural gas market movements, also decreased our relative operating cash inflows versus the prior fiscal period.

### *Net cash used in investing activities*

Net cash used in investing activities was \$32.9 million for the twelve months ended March 31, 2026 compared to net cash used of \$34.9 million for the twelve months ended March 31, 2025. The \$2.0 million decrease is primarily attributed to higher growth capital spending in fiscal 2025 related to capacity optimization capital projects at our Wild Goose facility undertaken in that year. The overall decline was offset to some extent by timing differences in making payments on projects, as certain costs incurred in the last quarter of fiscal 2025 were not cash paid until early fiscal 2026.

### *Net cash used in financing activities*

Net cash used in financing activities was \$319.8 million in the twelve months ended March 31, 2026 compared to net cash used of \$174.2 million for the twelve months ended March 31, 2025. Cash outflows during fiscal 2026 were mainly influenced by \$456.9 million in cash distributions and advances to Brookfield and Rockpoint. The distributions and advances paid in fiscal 2026 were funded through a combination of cash generated in fiscal 2025, of which \$204.1 million of cash held as at March 31, 2025 was carried over into fiscal 2026, and by cash generated in fiscal 2026. Other significant outflows included lease principal repayments of \$17.7 million, net repayments on the Business' revolving credit facilities of \$14.0 million, mandatory payments on the Term Loan due 2031 of \$12.5 million, and \$5.8 million in refinancing and repricing charges. These outflows were partially offset by a \$135.6 million loan received from Brookfield affiliates that was later contributed to the Business as capital and the \$51.5 million capital contribution received to fund partial payments on the Legacy Incentive Plans. Financing cash flows for the twelve months ended March 31, 2025 were primarily attributed to a combination of repayments of debt, including non-affiliated long-term debt of \$453.1 million and Brookfield affiliated debt of \$224.9 million, and to payments of cash distributions and advances to Brookfield totaling \$711.9 million. These financing cash outflows were partially offset by the issue of the Term Loan due 2031.

### ***Cash Flows of the Company***

The following table summarizes Rockpoint Gas Storage Inc.'s cash flows for the periods presented:

<b>(in millions, USD)</b>	<b>July 28, 2025 to March 31, 2026</b>
<b>Statements of Cash Flows Summary</b>	
<b>Net cash provided by operating activities</b>	<b>\$ —</b>
<b>Net cash used in investing activities</b>	<b>(489.5)</b>
<b>Net cash provided by financing activities</b>	<b>489.5</b>

### *Net cash provided by operating activities*

The Company did not have any significant cash inflows or outflows from operating activities for the period beginning July 28, 2025 and ended March 31, 2026. Cash expenses of the Company were paid on its behalf by a subsidiary of Swan OpCo, with offsetting related party payables recorded.

### *Net cash used in investing activities*

During the period beginning July 28, 2025 and ended March 31, 2026, as partial consideration for its acquisition of a 40% share in the Business, Rockpoint paid Brookfield the Canadian dollar cash generated from the Offering, which had a value of \$501.2 million on the transaction date of October 15, 2025. The remaining non-cash consideration was paid in Class A Shares. Offsetting the cash investment made was an \$11.7 million cash distribution received from the Business.

### *Net cash provided by financing activities*

During the period beginning July 28, 2025 and ended March 31, 2026, the Company received an advance from the Business totaling \$11.7 million, which was used to fund a distribution to Class A Shareholders. The advance was later settled on a non-cash basis when the Business distributed its amount receivable to the Company, thereby cancelling the amount by operation of law.

On October 15, 2025, the Company raised funds from its initial public offering of Class A Shares, with a value totaling \$501.2 million.

### ***Contractual Obligations and Commitments***

The following table summarizes the Business' contractual obligations as of March 31, 2026:

(in millions, USD)	Payment due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Debt obligations	\$ 1,234.4	\$ 12.5	\$ 25.0	\$ 25.0	\$ 1,171.9
Interest on debt obligations	393.8	73.8	145.2	142.0	32.8
Lease obligations	347.3	8.9	17.3	18.3	302.8
Gas storage obligations	17.1	0.2	2.3	14.6	—
Decommissioning obligations	253.4	—	0.7	—	252.7
Purchase obligations <sup>(1)</sup>	110.4	83.4	27.0	—	—
Other <sup>(2)</sup>	72.2	56.2	14.4	1.6	—
Total	<b>\$ 2,428.6</b>	<b>\$ 235.0</b>	<b>\$ 231.9</b>	<b>\$ 201.5</b>	<b>\$ 1,760.2</b>

#### **Notes:**

1. Our Business economically hedges substantially all of its natural gas purchases with forward sales obligations.
2. Other includes trade payables and accrued liabilities not included in separate categories above, committed costs of gas storage services, compensation obligations and firm storage transportation costs.

As of March 31, 2026, the debt obligations of the Business consisted entirely of Term Loan due 2031 debt as there were no cash drawings outstanding on the Revolving Credit Facility.

The Term Loan due 2031 bears interest at a floating rate. As of March 31, 2026, interest rates on drawings were either a base rate plus an applicable margin equal to 1.50% or, at our option, SOFR plus an applicable margin equal to 2.50%. As of March 31, 2026, floating interest rate exposure on the Term Loan due 2031 was fully hedged by interest rate swaps. The weighted average fixed rate, inclusive of interest rate swaps was 5.90%. Effective May 7, 2026, the Term Loan due 2031 was again repriced, reducing the hedged interest rate to 5.65%. See "Qualitative and Quantitative Disclosures about Market Risk - Interest Rate Risk" and "Liquidity and Capital Resources".

Our Business maintains long-term lease arrangements primarily related to surface and subsurface land use across our natural gas storage facilities in North America. These lease obligations represent the contractual cash payments required to satisfy the terms of the lease. As of March 31, 2026, the total discounted lease obligation was \$99.5 million (March 31, 2025 - \$108.8 million) of which \$90.9 million (March 31, 2025 - \$99.7 million) is classified as long-term in accordance with the lease terms.

The decommissioning obligations of the Business relate to the plugging and abandonment of its wells and decommissioning of our storage facilities at the end of their estimated useful economic lives. As of March 31, 2026, the estimated undiscounted cash flows required to settle the decommissioning obligations were approximately \$253.4 million (March 31, 2025 - \$258.2 million). At March 31, 2026, the expected timing of payment for settlement of the obligations was 54 years, aside from certain short-term well and other abandonment obligations.

Purchase obligations consist of forward physical commitments related to future purchases of natural gas inventory and cushion gas. As we economically hedge substantially all of our natural gas purchases for our Business, there are forward sales that offset these commitments, which include future sales of certain existing inventory.

Under a credit agreement entered into by BIF II Finco Borrower (Bermuda) L.P., an affiliate of Brookfield Infrastructure, for an amount of up to \$175.0 million, Swan OpCo was jointly and severally liable as a guarantor for the obligations of other affiliated borrowers under the facility. No amounts were called under the guarantee and the guarantee was terminated on September 26, 2025.

Pursuant to an exchange agreement entered into in connection with the Offering, from and after October 15, 2026, Brookfield has the right (the “Exchange Right”) to cause Rockpoint to acquire all or a portion of the OpCo interests held by Brookfield in exchange for, at Rockpoint’s election, Class A Shares, cash or a combination of both. The value of such exchange will be determined by reference to the prevailing market price or fair market value of the Class A Shares. However, as regulated California public utilities, any change of control of Wild Goose or Lodi is subject to the prior approval of the California Public Utilities Commission (“CPUC”). Accordingly, Brookfield is not permitted to exercise the Exchange Right to the extent that it would result in a change of control of Wild Goose or Lodi, unless the CPUC approval has first been obtained.

### **Capital Expenditures**

The following table summarizes the Business’ capital expenditures for the periods presented:

<b>(in millions, USD)</b>	<b>Fiscal Years Ended March 31,</b>	
	<b>2026</b>	<b>2025</b>
Growth capital expenditures	<b>\$ 0.9</b>	\$ 13.9
Maintenance capital expenditures	<b>26.4</b>	26.8
<b>Total capital expenditures</b>	<b>\$ 27.3</b>	\$ 40.7

Growth capital expenditures are investments that are expected to increase operating income over the long term through greater capacity, improved operational efficiency and efficient use of capital. In fiscal 2026, growth capital expenditures of \$0.9 million related to the Business’ purchase and workovers of wells and pipelines that expanded the operating efficiency of its WGS LP facility. During the fiscal year ended March 31, 2025, the Business undertook capacity optimization capital projects involving the drilling and tie-in of three new storage wells at our Wild Goose facility which primarily made up the \$13.9 million growth capital expenditures for that period.

In fiscal 2027 we will be exploring brownfield growth opportunities and advancing early stage greenfield projects. Final investment decisions depend on technical and financial feasibility studies. We anticipate that our growth capital efforts in fiscal 2027 will focus mainly on the following items:

- Design and construction of an 11 megawatt battery energy storage project at our Warwick facility.
- A potential expansion of our Warwick natural gas storage facility capacity of up to 5 Bcf.

Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives.

For the fiscal year ended March 31, 2026 our maintenance capital programs were primarily composed of the following items:

- Well inspections and well completions related to a multi-year California regulatory compliance program.
- General facility maintenance, overhauls and turnaround activities.
- Cushion gas purchases to replace ordinary course migrated cushion gas.

Planned maintenance capital for fiscal 2027 primarily consists of the following items:

- Preventative capital maintenance on our wells for items identified through our inspection program in fiscal 2026.
- General maintenance and facility upkeep.
- Cushion gas purchases to replace ordinary course migrated cushion gas.

### **Share Capital of Rockpoint Gas Storage Inc.**

On March 25, 2026, the Toronto Stock Exchange (“TSX”) accepted Rockpoint’s normal course issuer bid (“NCIB”) in respect to its Class A Shares. The NCIB commenced on March 27, 2026 and will terminate on the earlier of March 26, 2027, the date on which Rockpoint has purchased the maximum number of Class A Shares permitted under the NCIB or the date on which Rockpoint terminates the NCIB in accordance with its terms. Under the NCIB, Rockpoint may purchase, through the facilities of the TSX and/or other Canadian alternative trading systems, if eligible, up to 10% of the public float as of March 23, 2026, as defined by the TSX (representing approximately 5.3 million Class A Shares). Subject to certain exceptions for block purchases, the maximum number of Class A Shares that Rockpoint may acquire on any one trading day is 53,277. During the term of the NCIB, Rockpoint and the other parties to the exchange agreement entered into in connection with the Offering will undertake certain transactions to maintain the required one-to-one-to-one ratios between: (a) the number of outstanding Class A Shares and the interests in OpCos owned by the Company; and (b) the number of Class B Shares owned by Brookfield and the interests in OpCos owned by Brookfield. As a result, purchases of Class A Shares under the NCIB will not impact Rockpoint’s 40% economic or voting ownership interest in the Business. The Company did not repurchase any shares under its NCIB during fiscal 2026.

On July 28, 2025, in connection with its incorporation, the Company issued one common share to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration (\$0.01). This share was cancelled concurrent with amending of the Articles on September 17, 2025 and Brookfield Infrastructure Holdings (Canada) Inc. was issued one Class A Share.

On October 15, 2025, the Company completed its initial public offering and issued 32,000,000 Class A Shares. The Company also issued an additional 21,200,000 Class A Shares to Brookfield when it purchased its interest in the Business. Of the foregoing 21,200,000 Class A Shares, 4,800,000 were sold to the public pursuant to the October 2025 Secondary Offering by Brookfield on the same date as the initial public offering. On February 23, 2026, all remaining Class A shares held by Brookfield were sold to the public in the February 2026 Secondary Offering.

Concurrently with the close of the Offering, the single Class A Share held by Brookfield Infrastructure Holdings (Canada) Inc. was cancelled.

On October 15, 2025, concurrent with the Offering, the Company issued 79,800,000 Class B Shares to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration to align the voting interest of Brookfield Infrastructure Holdings (Canada) Inc. and certain of its affiliates in the Company with its economic interest in Swan OpCo and BIF OpCo.

As of both March 31, 2026 and May 27, 2026, in respect to the Company, there were (i) 53,200,000 Class A Shares outstanding (all of which were held by the public); (ii) 79,800,000 Class B Shares outstanding (all of which are held by Brookfield); and (iii) 132,844 unvested stock options outstanding. Upon vesting, each option is exercisable for one Class A Share.

Class A Share dividends are payable if, as and when declared by the Board of Directors of Rockpoint. The declaration, payment, amount and frequency of Class A Share dividends is at the discretion of the Company’s Board of Directors, which considers, among other things, the timing and amount of distributions declared and paid by the OpCos to the Company, economic conditions, the Company’s expenses, financial condition, results of operations, liquidity, earnings, projections, legal requirements, and restrictions in the agreements governing the Company’s indebtedness, including its credit facilities.

On November 5, 2025, Rockpoint’s Board of Directors declared the inaugural quarterly dividend of \$0.22 per Class A Share, which was paid on December 31, 2025 to Class A Shareholders of record as at the close of business on December 15, 2025.

On February 9, 2026, Rockpoint’s Board of Directors approved a quarterly dividend of \$0.22 per Class A Share, which was paid on March 31, 2026 to holders of Class A Shareholders of record as at the close of business on March 16, 2026.

On May 27, 2026, Rockpoint's Board of Directors approved a quarterly dividend of \$0.2310 per Class A Share, which is payable on June 30, 2026 to holders of Class A Shareholders of record as at the close of business on June 15, 2026.

### **Off-Balance Sheet Arrangements**

Currently and during the twelve months ended March 31, 2026 and 2025, neither the Company nor the Business has or had any off-balance sheet arrangements or any relationships with unconsolidated entities or financial partnerships, including entities (sometimes referred to as structured finance or special purpose entities) that were established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

### **Transactions Between Related Parties**

Brookfield has and will enter into a number of related party transactions with both Rockpoint and the Business. Rockpoint and the Business also enter into transactions with each other and other related parties in the normal course of business. Related party transactions are measured at the exchange amount, unless otherwise noted.

#### ***Transactions Between the Business and Rockpoint Gas Storage Inc.***

The Company is managed as a broader part of the Business under a shared management team with controlling interests held by Brookfield. Subsidiaries of Swan OpCo perform services for the Company for its day-to-day administration. For the period beginning July 28, 2025 and ended March 31, 2026, management fees charged by Rockpoint Gas Storage Canada Ltd., an indirect subsidiary of Swan OpCo, to the Company totaled \$1.6 million, all of which were receivable by the Business as of March 31, 2026. The Company and Business make use of transfer pricing studies to ensure that the management fees charged represent the best estimate of what arms-length parties would charge in similar circumstances.

The Company's treasury function is integrated with the payment system of the Business. During the year ended March 31, 2026, the Business made \$0.8 million of payments for the day-to-day expenses of the Company. All payments were made for third party costs and therefore represented market value.

On December 30, 2025, the Business advanced \$11.7 million in cash to the Company in exchange for a non-interest-bearing promissory note that was due on demand. On March 31, 2026, the Business settled the note, with consideration provided through a non-cash distribution of the related promissory note.

#### ***Transactions Between the Business and Brookfield***

The Business had transactions and balances outstanding with Brookfield classified as related parties as follows:

##### ***Promissory Note Payable***

During the fiscal year ended March 31, 2025, the Business had an outstanding promissory note due to affiliates of Brookfield Infrastructure bearing interest at 8.25%. This note was scheduled to mature on October 1, 2026 (the "8.25% Promissory Note due 2026").

On September 18, 2024, using proceeds from the Term Loan due 2031, the Business made principal and interest payments totaling \$233.5 million on the 8.25% Promissory Note due 2026, which were made in advance of the maturity date, without premium or penalty. The amounts paid consisted of the entire then outstanding principal balance of \$224.9 million and \$8.6 million in accrued interest.

##### ***Due from Affiliates***

On December 30, 2025, October 10, 2025 and May 29, 2025, the Business advanced \$17.6 million, \$40.0 million and \$37.0 million, respectively, to Brookfield parent entities in exchange for unsecured, non-interest-bearing promissory notes that are due on demand. These notes were settled through non-cash means on March 31, 2026, when the Business distributed the notes receivable as consideration.

On August 31, 2025, the Business settled \$83.0 million in promissory notes receivable from Brookfield by distributing its earnings in the form of promissory notes totaling the same amount, which offset the notes. The \$83.0 million balance was outstanding as of March 31, 2025.

On June 13, 2024 and September 18, 2024, the Business advanced cash totaling \$50.0 million and \$472.2 million, respectively, to certain Brookfield parent entities in exchange for unsecured, non-interest-bearing promissory notes that were due on demand. During the fourth quarter of fiscal 2025, a total of \$439.2 million of these notes were settled through non-cash distributions. As noted above, the remaining \$83.0 million remained outstanding until August 2025.

As the above promissory notes were non-interest-bearing and part of groups of transactions related to distributions, they have been presented as financing cash outflows.

#### *Other Related Party Transactions*

The Business has market-based contracts with a utility company related to Brookfield for the purchase of electricity. During the year ended March 31, 2026, we incurred \$2.4 million in costs from this counterparty (March 31, 2025 – \$3.0 million) and recognized \$0.4 million of current liabilities as of March 31, 2026 with this related party (March 31, 2025 – \$0.4 million).

During the year, the Business paid \$0.1 million to a Brookfield affiliated entity for financing related services. The services were charged at a market rate.

#### ***Transactions Between Rockpoint Gas Storage Inc. and Brookfield***

As related to Brookfield's sale of 40% of its economic interest in the Business, withholding taxes were required to be remitted by the Company on behalf of certain selling Brookfield affiliates. The Company had an escrow agreement in place with the related Brookfield affiliates to hold the funds until formal clearances were provided by taxation authorities, which totaled \$57.5 million at the time of the acquisition in October 2025. Up to March 31, 2026, after receiving the required clearances, the Company remitted \$43.5 million to taxation authorities, and collected \$0.3 million of interest income on behalf of Brookfield. The \$14.8 million March 31, 2026 balance of restricted cash included a positive change of \$0.5 million due to a strengthening of the Canadian dollar. As of March 31, 2026, the Company's related party payables balance included a \$14.8 million offset to the restricted cash amount. The restricted cash and offsetting related party payables were settled subsequent to March 31, 2026.

#### ***Compensation of Key Management Personnel***

For the year ended March 31, 2026, the Business provided \$46.1 million (March 31, 2025 - \$5.5 million) in compensation to its key management personnel who include the Business' senior executive officers. Of the fiscal 2026 key management compensation, \$42.2 million was related to the Legacy Incentive Plans payments, see "Notable Transactions". Members of the Board of Directors are compensated by the Company.

The Company's key management personnel consists of senior executive officers employed by the Business, for which a management fee is charged to the Company, and directors who were compensated by the Company via cash director fees and deferred share units, for which \$0.4 million was incurred during the period beginning July 28, 2025 and ended March 31, 2026.

#### **Qualitative and Quantitative Disclosures about Market Risk**

We are exposed to market risks in the ordinary course of business. Market risk represents the risk of loss that may impact our financial position due to adverse changes in financial market prices and rates. Our market risk exposure is primarily the result of fluctuations in interest rates and commodity prices.

##### *Interest Rate Risk*

To the extent that it is economic to do so, our Business enters into interest rate swaps to hedge the exposure from its variable interest rates. We use derivatives to manage or maintain exposure to changes in interest rates given the Term Loan due 2031 borrowings are indexed against SOFR. Through borrowings on our Revolving Credit Facility, we are exposed to interest rate fluctuations on our USD prime rate and SOFR borrowings and, with respect to Canadian dollar borrowings, if any, CORRA, Canadian prime rate and daily compound CORRA.

Our Business entered into interest rate swaps contracts to hedge the exposure from the Term Loan due 2031. Effective October 24, 2025, we locked in a blended 3.40% SOFR interest rate, effectively a 5.90% all-in rate for SOFR denominated loans, on all of the remaining projected principal borrowings, which were based on the principal balance outstanding as of the date of the revised hedging transactions less mandatory principal repayments required over the term of the loan that are drawn using three-month SOFR terms. Effective May 7, 2026, the Term Loan due 2031 was again repriced, reducing the hedged interest rate to 5.65%, see “Liquidity and Capital Resources”.

As of March 31, 2026, we had no cash drawings on our Revolving Credit Facility and were therefore not exposed to variable interest rates on that facility.

#### *Commodity Price Risk*

As a result of our natural gas inventory and any future requirements to purchase cushion gas, we are exposed to risks associated with changes in price when buying and selling natural gas across future time periods. To manage these risks and reduce the variability of cash flows, our Business utilizes a combination of financial and physical derivative contracts, including forwards, futures and swap contracts. To limit our exposure to changes in natural gas prices, we enter into purchases and sales of natural gas inventory and concurrently match the volumes in these transactions with offsetting derivative contracts. The Business maintains internal risk management policies that require it to limit its exposure to unmatched volumes of proprietary natural gas inventory.

Our Business uses electricity to run certain compressors used to inject and withdraw natural gas and is also exposed to risks associated with changes in the price of electricity. To manage these risks and reduce the variability of cash flows, we utilize swap contracts to hedge the price of electricity.

#### *Risk Management Assets and Liabilities*

The following table summarizes the Business’ net realized and unrealized gains and losses from our derivative financial instruments:

(in millions, USD)	Three Months Ended March 31,		Fiscal Years Ended March 31,	
	2026	2025	2026	2025
Energy contracts	\$ 29.4	\$ 29.5	\$ 79.3	\$ 55.5
Electricity contracts	(0.1)	(0.2)	(0.2)	(0.6)
Interest rate swaps	0.8	1.4	6.7	3.8
Currency contracts	(0.1)	0.4	(0.5)	1.1
<b>Net realized gains</b>	<b>\$ 30.0</b>	<b>\$ 31.1</b>	<b>\$ 85.3</b>	<b>\$ 59.8</b>
Energy contracts	\$ (8.1)	\$ (10.8)	\$ 11.7	\$ (8.1)
Electricity contracts	(0.2)	(0.2)	0.2	(0.1)
Gas storage obligations	1.4	(0.3)	4.5	1.3
Interest rate swaps	7.3	(3.3)	8.2	2.9
Currency contracts	0.7	(0.4)	0.4	—
<b>Net unrealized gains (losses)</b>	<b>\$ 1.1</b>	<b>\$ (15.0)</b>	<b>\$ 25.0</b>	<b>\$ (4.0)</b>

Certain of the Business’ financial assets and liabilities are recorded at fair value on a recurring basis. The key inputs used in our valuation of our energy commodity assets and liabilities include transaction-specific details such as notional volumes, contract prices, and contract terms, as well as forward market prices and basis differentials for natural gas obtained from third-party service providers (typically the New York Mercantile Exchange, or NYMEX). In valuing our interest rate swaps, we used forward market data for three-month SOFR loans obtained from third-party banking service providers. The value of our foreign exchange swaps are calculated in reference to Bank of Canada published data.

#### *Other Risk Factors*

Other risks that may affect the Company and the Business are described in the annual information form (“AIF”), a copy of which is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca).

## Material Accounting Policies and Estimates and Changes in Accounting Policies

### *Changes in material accounting policies of the Business*

We applied, for the first time, certain accounting policies that became applicable to the Business during the fiscal year ended March 31, 2026. The impact of these accounting policies are as follows:

#### *Share-based Compensation*

The Business, in conjunction with Rockpoint, has adopted incentive plans that allow the granting of share-based compensation to key directors, officers and employees. These incentive plans provide for grants of (i) performance share units that vest based on satisfaction of specified performance conditions (“PSUs”); (ii) restricted share units that vest on time-satisfied conditions (“RSUs”); and (iii) stock options that vest 20% on each of the first five anniversaries of the grant date.

The Business measures all goods and services received in exchange for share-based payment awards at their fair value. Where the fair value of goods or services cannot be directly determined, it is estimated using an appropriate option pricing model. For employee share-based awards, the fair value is determined by reference to the fair value of the equity instruments granted, calculated at the grant date. The value of these plans are derived by reference to publicly traded Class A common shares issued by Rockpoint.

At Rockpoint’s option, vested PSUs and RSUs can be settled by delivering cash, Class A common shares or a combination thereof. Where Rockpoint or the participating entities of the Business intend to settle PSUs or RSUs compensation in cash, an expense is recognized with a corresponding liability equal to the fair value of the compensation. Stock options are classified as equity settled.

The fair value of stock options is determined at the grant date using the Black-Scholes option pricing model. Key inputs in this model include the share price on the measurement date, the exercise price, the weighted average term of the stock options, expected volatility of Rockpoint’s share price, as well as volatility of comparable companies having midstream natural gas operations, an estimated dividend yield, expected forfeitures and a risk free rate referenced to Bank of Canada yields. The resulting expense is recognized over the vesting period, based on the estimated number of stock options expected to vest. For stock options with graded vesting, the expense is allocated over the relevant vesting periods, with a corresponding increase in equity.

#### *Critical Accounting Judgments and Key Sources of Estimation Uncertainty*

In preparing the combined consolidated financial statements, we are required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: fair value of derivatives and other financial instruments, assessment of inventory adjustments, the recoverable amount of goodwill and other long-lived assets, income taxes, cushion gas migration, provisions for decommissioning obligations, gas storage obligations and recognizing lease liabilities and ROU assets. Management uses the most current information available and exercises careful judgment in making these estimates. Although management believes that these combined consolidated financial statements have been prepared within the limits of materiality and within the framework of its material accounting policy information summarized above and below, actual results could differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

#### *a. Fair Value of Risk Management Assets and Liabilities*

The determination of the fair value of natural gas derivatives and other financial instrument contracts reflects the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

There are uncertainties in our methodology in the determination of fair value since it requires the Business to consider various factors, including over-the-counter quotations, customer attrition, costs of fulfillment, location differentials and closing interest and foreign exchange rates underlying the contracts. Although the fair value of risk management assets and liabilities may fluctuate for commodity risk contracts, such fluctuations are offset by equivalent changes in the value of our physical inventory. Our policy is for our inventory and purchases to be economically hedged, within small tolerances permitted under our risk management policy; therefore, we reduce our economic exposure to the risk of fluctuating commodity prices.

*b. Inventory*

The Business' inventory is natural gas injected into storage and held for resale. Inventory is valued at the lower of weighted average cost or net realizable value. Adjustments to the carrying value of inventory to net realizable value are recorded as an offset to optimization, net while costs to store the gas are recognized as operating expenses in the period the costs are incurred.

At the end of each reporting period, management determines whether an adjustment is required to reduce the carrying value of inventory to the lower of weighted average cost or net realizable value. This determination has built-in uncertainties since it requires judgment in both estimating fair market values in the periods in which our inventory can be sold and the volumes that can be sold in those periods.

*c. Impairment of Long-lived Assets*

The Business evaluates whether events or circumstances have occurred that indicate that long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, management assesses the recoverability of long-lived assets by comparing the higher of (1) fair value less costs of disposal or (2) the value in use and eventual disposal from an asset or CGU to their carrying value. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail.

The Business' estimate for the impairment of long-lived assets contains uncertainties since it requires management to make a judgment on fair value, cost of disposals and expected value from the continued use of long-lived assets.

*d. Income Taxes*

The Business is predominantly not a taxable entity in the United States. Income taxes for such entities are the responsibility of the equity holders and have accordingly not been recorded in the combined consolidated financial statements.

The Business has corporate subsidiaries, which are taxable corporations subject to Canadian federal and provincial income taxes, which are included in the combined consolidated financial statements.

The Business' accounting of its income taxes has inherent uncertainties since it requires an estimate of the timing of the realization of its tax assets and liabilities, including the allocation of income among different entities and tax jurisdiction, and also requires us to make assumptions on the estimated probabilities of utilization of deferred tax assets and on the determination of tax exposures associated with our tax filing positions.

*e. Cushion Gas Effectiveness*

Certain volumes of cushion gas are required for maintaining a minimum reservoir pressure. Owned cushion gas is considered a component of the facility and as such is not depreciated because of its indefinite useful life. Cushion gas is monitored to ensure that it provides effective pressure support. In the event that natural gas moves to another area of the reservoir where it does not provide effective pressure support or is withdrawn due to heat imbalances of native cushion volumes, charges against cushion gas are included in depreciation in an amount equal to the cost of estimated volumes that have migrated.

Cushion gas requirements and its effectiveness are estimated using pressure and volumetric data accumulated over many years of storage operation.

*f. Provisions for Decommissioning Obligations*

Decommissioning, abandonment, and site reclamation expenditures for storage facilities, wells and pipelines are expected to be incurred by the Business over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

*g. Gas Storage Obligations*

Gas storage obligations are measured at fair value based on contracted volumes, estimated external forward price curves available at period end and an estimated discount rate applicable to the liabilities. Changes in forward pricing between period end and maturity of the derivative contracts could have a material impact on their carrying value.

*h. Recognition of Lease Liabilities and Right of Use Assets*

The Business has applied critical judgments in the application of lease accounting standards, including: i) identifying whether a contract, or part of a contract, includes a lease; ii) determining whether it is reasonably certain that lease extension or termination options will be exercised in determining the lease term; and iii) determining whether variable payments are in-substance fixed. We also use critical estimates in the application of lease accounting standards, including the estimation of lease term and determination of the appropriate rate to discount the lease payments. For leases that can be renewed into perpetuity at our option, a 60-year timeframe has been used as an estimate to measure the liability, ROU asset offset and undiscounted future cash outflows. Under the discount rates applicable to our leases, substantially all of the present value is contained within the first 60 years.

*i. Reportable Segments*

Management has determined that the Business has a single reportable segment, natural gas storage. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), as the chief operating decision makers, review combined consolidated financial information when making decisions about resource allocation and assessing performance.

*Future Accounting Policies*

*a. Amendments to IFRS 9, Financial Instruments ("IFRS 9") and IFRS 7, Financial Instruments: Disclosures ("IFRS 7") - Classification and Measurements of Financial Instruments*

In May 2024, the IASB issued amendments which clarify the requirements for the timing of recognition and derecognition of financial liabilities settled through an electronic cash transfer system, add further guidance for assessing the contractual cash flow characteristics of financial assets with contingent features, and add new or amended disclosures relating to investments in equity instruments designated as fair value through other comprehensive income ("FVOCI") and financial instruments with contingent features. The amendments to IFRS 9 and IFRS 7 are effective for fiscal periods beginning on or after January 1, 2026, with early adoption permitted. The Business has assessed these amendments and determined that they are not expected to have a material impact on its financial statements.

*b. IFRS 18 – Presentation and Disclosure in Financial Statements ("IFRS 18")*

In April 2024, the IASB issued IFRS 18, "Presentation and Disclosure of Financial Statements". IFRS 18 is effective for fiscal periods beginning on or after January 1, 2027, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring separate categories and defined subtotals for operating, investing and financing activities in the statement of profit or loss, requiring disclosure about management defined performance measures, and adding new principles for aggregation and disaggregation of information. The Business is in the process of determining the impact of adopting IFRS 18 on its financial statements.

***Material Accounting Policies of Rockpoint Gas Storage Inc.***

Rockpoint, as a newly created entity, along with its acquisition of its share of the OpCos, recently adopted the accounting policies outlined below.

### *Cash and Cash Equivalents*

Cash and cash equivalents include cash on hand, and as applicable, short-term investments with original maturities of three months or less.

### *Restricted Cash*

Restricted cash represents cash and cash equivalents that are not available to be distributed or used in ordinary course operations due to contractual or other restrictions.

### *Equity Accounted Investments*

The equity method of accounting is used when the Company can exercise significant influence over an investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee but does not constitute control. Under the equity method, investments are initially recorded at cost and subsequently adjusted by the Company's share of the investee's income or loss, less distributions received.

### *Impairment of Long-lived Assets*

At each reporting date, the Company assesses if there is objective evidence that its net investment in an equity accounted associate is impaired. This assessment includes a review of internal and external factors related to the underlying investment including, but not limited to, changes in the technological, economic or legal environment in which an associate operates, structural changes in the industry, changes in the level of demand, physical damage and obsolescence due to technological changes. When necessary, the entire carrying amount of an equity accounted investment (including goodwill) is tested for impairment as a single asset by comparing its recoverable amount (which is the higher of value in use and fair value less costs of disposal) with its carrying amount. Any impairment loss recognized in an equity accounted investment is not allocated to the individual assets (including goodwill) that form part of the carrying amount of the asset. If a subsequent impairment assessment indicates a reversal of impairment has occurred, any such loss previously recognized is reversed to the lesser of the revised estimate or the carrying amount that would have been recorded had no impairment loss been recognized.

### *Foreign Currency Translation*

The reporting and functional currency of the Company is the U.S. dollar. Foreign currency-denominated assets and liabilities are translated into U.S. dollars at the period-end exchange rate. Foreign currency-denominated income and expenses are translated at applicable average exchange rates. Non-monetary items measured at historical cost are translated at the exchange rate in effect on the date of the transaction. Foreign exchange gains and losses arising from monetary transactions denominated in currencies other than the functional currency are recognized in net earnings for the period.

### *Current Income Tax*

Current income tax assets and liabilities for the current period are measured at the amount expected to be recovered from or paid to taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted, or substantively enacted at the reporting date in the countries where the Company operates and generates taxable income.

### *Deferred Tax*

Deferred tax is provided using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date. Deferred tax liabilities are recognized for all taxable temporary differences, except:

- when the deferred tax liability arises from the initial recognition of goodwill or an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and

- in respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, when the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences and the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available to use against the deductible temporary differences. The carry forward of unused tax credits and unused tax losses can be utilized, except:

- when the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and
- in respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available, against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized, or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized outside net earnings (loss) are recognized in correlation to the underlying transaction either in other comprehensive income (loss) or directly in equity.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to offset current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority. Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognized subsequently if new information about facts and circumstances change. The adjustment is either treated as a reduction to goodwill (if applicable, and as long as it does not exceed goodwill) if it is incurred during the measurement period or recognized in net earnings (loss).

#### *Share-based Compensation*

The Company, in conjunction with certain participating entities of the Business, has adopted incentive plans that allow the granting of share-based compensation to key directors, officers and employees. These incentive plans provide for grants of (i) performance share units that vest based on satisfaction of specified performance conditions (“PSUs”); (ii) restricted share units that vest on time-satisfied conditions (“RSUs”); (iii) deferred share units (“DSUs”) that vest immediately, and (iv) stock options that vest 20% on each of the first five anniversaries of the grant date.

The Company measures all goods and services received in exchange for share-based payment awards at their fair value. Where the fair value of goods or services cannot be directly determined, it is estimated using an appropriate option pricing model. For employee share-based awards, the fair value is determined by reference to the fair value of the equity instruments granted, calculated at the grant date. The value of these plans are derived by reference to publicly traded Class A Shares.

At the Company’s option, the vested PSUs and RSUs can be settled by delivering cash, Class A Shares or a combination thereof. Where the Company or the participating entities of the Business intend to settle PSUs or RSUs in cash, an expense is recognized with a corresponding liability equal to the fair value of the compensation. DSUs are required to be settled in cash while stock options are classified as equity settled.

The fair value of stock options is determined at the grant date using the Black-Scholes option pricing model. Key inputs in this model include the share price on the measurement date, the exercise price, the weighted average term of the stock options, the expected volatility of the Company's share price, as well as volatility of comparable companies having midstream natural gas operations, an estimated dividend yield, expected forfeitures and a risk free rate referenced to Bank of Canada yields. The resulting expense is recognized over the vesting period, based on the estimated number of stock options expected to vest. For stock options with graded vesting, the expense is allocated over the relevant vesting periods, with a corresponding increase in equity.

#### *Critical Accounting Judgments and Key Sources of Estimation Uncertainty*

In preparing the financial statements, management is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, income and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include estimating the recoverable amount of long-lived assets and the amount and timing of income tax assets and liabilities. Management uses the most current information available and exercises careful judgment in making these estimates. Although management believes that these financial statements have been prepared within the limits of materiality and within the framework of its material accounting policy information summarized above and below, actual results could differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

##### *a. Impairment of Long-lived Assets*

The Company evaluates whether events or circumstances have occurred that indicate the carrying amount of an equity accounted investment may not be recoverable. When such events or circumstances are present, management assesses the recoverability of the investment by comparing the higher of the value in use or the fair value less costs of disposal. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail. The Company's estimate of the impairment of an equity accounted investment contains uncertainties since it requires management to make judgments regarding fair value, cost of disposals and expected value from the continued use of the underlying assets.

##### *b. Income Taxes*

A portion of the Company's equity accounted investments is comprised of entities that are not directly taxable. The Company is responsible for income taxes generated from its proportionate share of earnings from these entities and reports such amounts directly in its financial statements.

The equity accounted investments also contain taxable Canadian corporations which are directly subject to Canadian federal and provincial income taxes. The impact of such income taxes is not directly reported by the Company and is instead included as part of the share of income from equity accounted investees.

The Company's accounting of its income taxes has inherent uncertainties since it requires an estimate of the timing of the realization of its tax assets and liabilities, including the allocation of income among different entities and tax jurisdiction, and also requires us to make assumptions on the estimated probabilities of utilization of deferred tax assets and on the determination of tax exposures associated with our tax filing positions.

##### *c. Basis Adjustments Related to Equity Accounting*

The Company's equity-accounted investments include certain basis differences arising from the gap between the fair value of underlying assets and liabilities at acquisition and their carrying (historical) values. Management is required to apply significant judgment in allocating these fair value differences among the underlying assets and liabilities and in determining the appropriate method for amortizing such differences over time. These judgments directly affect the income recognized from equity-accounted investees.

Key estimates and assumptions include the methodology used to allocate the fair value at the investment's acquisition among the various underlying assets and liabilities, projections of future cash flows and associated probabilities for each underlying operation, the selection of appropriate discount rates and terminal value assumptions, and estimates of the replacement cost of property, plant and equipment within the investments.

#### *Future Accounting Policies*

##### *a. Amendments to IFRS 9, Financial Instruments ("IFRS 9") and IFRS 7, Financial Instruments: Disclosures ("IFRS 7") - Classification and Measurement of Financial Instruments*

In May 2024, the IASB issued amendments which clarify the requirements for the timing of recognition and derecognition of financial liabilities settled through an electronic cash transfer system, add further guidance for assessing the contractual cash flow characteristics of financial assets with contingent features, and add new or amended disclosures relating to investments in equity instruments designated as fair value through other comprehensive income ("FVOCI") and financial instruments with contingent features. The amendments to IFRS 9 and IFRS 7 are effective for fiscal periods beginning on or after January 1, 2026, with early adoption permitted. The Company has assessed these amendments and determined that they are not expected to have a material impact on its financial statements.

##### *b. IFRS 18 - Presentation and Disclosure in Financial Statements ("IFRS 18")*

In April 2024, the IASB issued IFRS 18, "Presentation and Disclosure of Financial Statements". IFRS 18 is effective for fiscal periods beginning on or after January 1, 2027, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring separate categories and defined subtotals for operating, investing and financing activities in the statement of profit or loss, requiring disclosure about management defined performance measures, and adding new principles for aggregation and disaggregation of information. The Company is in the process of determining the impact of adopting IFRS 18 on its financial statements.

#### **Disclosure Controls and Procedures and Internal Control over Financial Reporting**

Rockpoint has established and maintains disclosure controls and procedures ("DC&P"), as such term is defined in National Instrument 52-109 – *Certification of Disclosure in Issuer's Annual and Interim Filings* ("NI 52-109"). The Chief Executive Officer and Chief Financial Officer of Rockpoint, with the assistance of management, have evaluated the effectiveness of the Company's DC&P as at March 31, 2026 and the Chief Executive Officer and Chief Financial Officer of the Company have concluded that, as of such date, Rockpoint's DC&P were effective in providing reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings and other reports filed or submitted by it under applicable securities laws is: (a) recorded, processed, summarized and reported within the time periods specified in applicable securities legislation; and (b) accumulated and communicated to Rockpoint's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

In addition, Rockpoint has established and maintains internal controls over financial reporting ("ICFR"), as such term is defined in NI 52-109, which are designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with IFRS. The Chief Executive Officer and Chief Financial Officer of Rockpoint, with the assistance of management, have evaluated the design and effectiveness of the Company's ICFR as at March 31, 2026 based on the framework set forth in *Internal Control – Integrated Framework* issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of the Company have concluded that the design and operation of Rockpoint's ICFR were effective as at March 31, 2026. There have been no changes during the financial year ended March 31, 2026 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Establishing and maintaining adequate control systems has inherent limitations and, as a result, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud or error, if any, have been detected.

#### **Additional Information**

Additional information relating to the Company and the Business, including the AIF, is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca).

## Forward-Looking Information

This MD&A contains “forward-looking information” within the meaning of applicable securities laws (“forward-looking information”). Forward-looking information includes statements regarding possible events, conditions, performance or results that are based on Rockpoint's current expectations, estimates and assumptions regarding future events or circumstances. Forward-looking information is often identified by words such as “may”, “will”, “would”, “should”, “could”, “expects”, “plans”, “intends”, “trends”, “indicates”, “anticipates”, “believes”, “estimates”, “predicts”, “likely”, “potential” or similar expressions suggesting future events or circumstances.

In particular, forward-looking information in this MD&A includes, among other things, information relating to: financial outlooks and other statements regarding the future financial performance, financial condition or cash flows of the Company and the Business, including Rockpoint's long-term annual Adjusted EBITDA and Distributable Cash Flow (both baseline and incremental) growth targets and its Net Debt to Adjusted EBITDA target; statements regarding current and future market conditions, trends and industry activities, including the Company's expectations with respect to developments and trends in the North American natural gas industries, the key drivers in respect thereof and their anticipated impacts on the Business; the demand, volatility and price of energy, natural gas and gas storage; the Company's strategic and business initiatives, assets, market positioning and growth opportunities, including the potential for accretive capital projects and strategic acquisitions; expectations regarding the Company's capital structure, including statements regarding future cash flows, borrowing capacity, indebtedness, access to capital and the availability and sufficiency thereof; future dividend and distribution payments by the Company and the OpCos, including the occurrence, timing and amount thereof and factors considered in connection therewith; expectations regarding future natural gas storage contracts and any terms thereof, including the Company's future contracting mix; internal risk policies and risk management strategies, including hedging activities and the effectiveness and impact thereof; the seasonality of the business; expectations regarding future capital expenditures, including the nature, amount and timing thereof; plans and expectations with respect to future operations, including anticipated facility performance, capital expenditures and economic returns, future working gas storage capacity and deliverability, regulatory applications and approvals and the results and timing thereof; and the development, timing and outcomes of existing and future development opportunities and projects.

Forward-looking information is based on various factors and assumptions made by the Company as of the date hereof, including with respect to: expectations in respect of the Company's and the OpCos' ability to build market share and achieve their targets and goals, including Rockpoint's long-term annual Adjusted EBITDA and Distributable Cash Flow growth targets and its Net Debt to Adjusted EBITDA target; the supply, demand and pricing for natural gas being consistent with management's expectations, including the level and volatility thereof; oil and gas industry development activity levels and general business, economic and industry conditions; the legal and regulatory environment, including the Company's ability to effectively anticipate and assess its treatment under existing and proposed legislation and regulations; the Company's ability to obtain all required regulatory approvals on acceptable terms and in a timely manner; expected growth, performance and results of operations being consistent with past performance and management's expectations in relation thereto; the availability and reliability of Rockpoint's assets; the Company's ability to successfully complete development opportunities and projects on budget and schedule; the ability to recruit and retain key personnel; the Company's ability to obtain or maintain financing on acceptable terms; future commodity prices, exchange rates, interest rates and tax rates; the impact of competition; future operating, maintenance and capital costs being consistent with current estimates; weather patterns and seasonality being consistent with historical patterns; the Company's ability to maintain its current dividend policy and achieve its targeted annual dividend growth; and the stability and continuation of the Company's relationship with Brookfield and the governance arrangements contemplated by the agreements between the Company and Brookfield.

Rockpoint believes that the factors and assumptions reflected in the forward-looking information contained in this MD&A are reasonable as of the date hereof based on information currently available. However, no assurance can be provided that such factors and assumptions will prove to be correct and forward-looking information should not be unduly relied upon or read as a guarantee of future events, conditions, performance or results. Forward-looking information involves a number of known and unknown risks, uncertainties and other factors, many of which are beyond Rockpoint's control, that may cause actual events, conditions, performance or results to differ materially from that expressed or implied by such forward-looking information. Such risks, uncertainties and other factors include: adverse changes in the supply, demand or pricing for natural gas; unfavorable business, economic and industry conditions; adverse changes in commodity prices, exchange rates, interest rates or tax rates; adverse actions or decisions by governmental or regulatory authorities, including adverse changes in laws, regulations or royalty rates, the imposition of new tariffs or other changes in international trade policies or relations, increased environmental regulations or adverse regulatory decisions or changes in regulatory processes; changing expectations of stakeholders and government policies regarding sustainability, climate change, and environmental and social practices; growth projects and other initiatives may not achieve the expected results in the time anticipated or at all; operating risks; fluctuations in operating or financial results, including risks related to the seasonality of the Business; competition from existing and new competitors; reliance on third party assets and services and on key relationships and agreements; non-performance or default by contractual counterparties; risk management costs and limitations; credit and counterparty risks; weather and climate-related risks, including those relating to climate change; technology and security risks (including cybersecurity risks); risks related to Rockpoint's dependence on distributions from the OpCos; risks related to Brookfield's majority ownership interest in the Company; and other risks, uncertainties and factors described from time to time in Rockpoint's public disclosure documents available on the Company's SEDAR+ profile at [www.sedarplus.ca](http://www.sedarplus.ca), including those discussed under the heading "Risk Factors" in the AIF.

The foregoing list of factors, assumptions and risks is not exhaustive of all assumptions which may have been used in developing forward-looking information or of all risks that could cause actual events, conditions, performance or results to differ materially from that expressed or implied by forward-looking information. The forward-looking information contained in this MD&A represents the Company's expectations as of the date hereof and, except as required by applicable securities laws, Rockpoint undertakes no obligation to publicly update or revise any forward-looking information, whether as a result of new information, future events or otherwise. Management approved the financial outlooks contained in this MD&A, including Rockpoint's long-term annual Adjusted EBITDA and Distributable Cash Flow growth targets and its Net Debt to Adjusted EBITDA target, as of the date hereof. The purpose of these financial outlooks is to assist readers in understanding the Company's targeted financial results and financial position, and this information may not be appropriate for other purposes. All forward-looking information in this MD&A is expressly qualified in its entirety by this cautionary statement.