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A PROFESSIONAL CORPORATION

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July 1, 2026

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

Subject: Oliktok Pipeline Company
Tariff Advice Letter No. TL57-334

Dear Commissioners:

On behalf of Oliktok Pipeline Company ("Oliktok"), the tariff filing described herein is transmitted to the Regulatory Commission of Alaska ("Commission") for filing in compliance with the Pipeline Act (AS 42.06) and 3 AAC 48.200 — 3 AAC 48.430.

Sheet Number		Cancels Sheet Number		Schedule or
Original	Revised	Original	Revised	Rule Number
37	9th	37	8th	Schedule A

I. INTRODUCTION

By this filing, Oliktok requests Commission approval to change its existing intrastate natural gas transportation service rates. The requested rate changes are based on a revenue requirement study for the normalized test year ending December 31, 2025. Oliktok requests that the Commission approve the proposed rate changes effective August 1, 2026, the day after expiration of the statutory 30-day notice period.

The proposed rates are shown on the enclosed ninth revision to Tariff Sheet No. 37 of Oliktok's tariff. *See* Exhibit 1. The current and proposed rates are as follows:

From	To	Current Permanent Rates ($/MSCF[1])	Proposed Rates ($/MSCF)
Prudhoe Bay Unit	Gas Hydrates Project	$0.346	$0.914
Prudhoe Bay Unit	Gas Spur Pipeline	$0.555	$1.464
Prudhoe Bay Unit	Kuparuk River Unit	$0.580	$1.528

Notices, orders, pleadings, and communications regarding this matter should be directed to:

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Emily M. Walker
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II. NEED FOR PROPOSED RATE CHANGES

Oliktok's existing rates were filed on December 1, 2025, in Tariff Advice Letter No. 56-334 ("TL56-334"). The Commission approved those rates effective January 1, 2026. *See* Letter Order No. L2500352 (Dec. 18, 2025). By Letter Order No. L2100300 (Aug. 25, 2021), the Commission required Oliktok to submit a 3 AAC 48.275(a) rate case (revenue requirement study and prefiled testimony) by July 1, 2026, based on a 2025 test year. *See* Letter Order No. L2100300 (Aug. 25, 2021). This filing satisfies that requirement.

The requested rate increases are necessary to reflect Oliktok's normalized test year costs and current throughput volumes. Revenues under the existing rates are below Oliktok's costs and are causing Oliktok to under-recover its annual revenue requirement. Based on normalized test year 2025 results, Oliktok witness Erik G. Wetmore calculates that Oliktok has a total annual revenue deficiency of approximately $7.4 million, which requires that existing rates increase by approximately 164% in order for Oliktok to have a reasonable opportunity to recover its revenue requirement. *See* Prepared Direct Testimony of Erik G. Wetmore at 3-4; Exh. EGW-2, Sch. 4 and 5; Exh. EGW-3.

[1] $ per thousand standard cubic feet.

III. REQUEST FOR PERMANENT, AND TEMPORARY AND REFUNDABLE, RATE CHANGES

Oliktok requests that its proposed rate changes be approved on a permanent basis. If the Commission suspends operation of this filing, Oliktok requests that the proposed rate changes ("filed rates") be approved on a temporary and refundable basis ("temporary rates") pending adjudication of permanent rates, without the need for Oliktok or its shippers to deposit any funds in escrow.[2] This treatment is consistent with the manner in which the Commission has treated similar transportation rate change requests by pipeline carriers in the past. *See*, *e.g.*, Order No. P-15-006(1); Order No. P-13-010(1); Order No. P-12-017(1); Order No. P-11-011(1); Order No. P-10-010(1); Order No. P-09-010(1); Order No. P-08-009(1).

The Commission evaluates requests for interim rate relief under the legal standard established in *Alaska Public Utilities Commission v. Greater Anchorage Area Borough* ("*GAAB*"), 534 P.2d 549 (Alaska 1975). The "*GAAB* standard" provides for interim and refundable rate relief when a utility or pipeline carrier demonstrates that:

1. Its existing rates are confiscatory;

2. Those confiscatory rates will remain in effect for an unreasonably long period of time;

3. The utility or pipeline carrier will suffer irreparable harm in the event that interim relief is not granted;

4. If interim relief is granted, the ratepayer can be adequately protected; and

5. The utility or pipeline carrier has raised "serious" and "substantial" questions going to the merits of the case (i.e. the rate request is not "frivolous or obviously without merit").

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[2] Under AS 42.06.400(c), the Commission is required to establish a reasonable temporary rate if a proposed increased rate is suspended. The Commission may require collection of either the temporary rates or the proposed increased filed rates, and must order the difference between the temporary rates and the filed rates placed in escrow. If the temporary rates are equal to the proposed filed rates, and are approved subject to refund, including interest at the rate set forth in AS 45.45.010(a), no escrowing of funds by the pipeline or its shippers is required. *See, e.g.* Order No. P-15-006(1) (Apr. 17, 2015) at 4-5 (approving Oliktok temporary rates in its test year 2014 rate case).

The circumstances reflected in Oliktok's revenue requirement study (Exhibits EGW-2 and EGW-3) and prepared direct testimony demonstrate that Oliktok is entitled to the requested interim rate relief under the *GAAB* standard. Addressing the elements of the standard in order:

1. Exhibit EGW-3 shows that Oliktok has a substantial annual revenue deficiency of approximately $7.4 million under its current rates. Thus, current rates are so low as to not allow Oliktok a reasonable opportunity to recover a reasonable rate of return of and on its investment and, thus, are confiscatory.

2. If the Commission suspends Oliktok's request for a permanent rate increase, the currently effective rates can be anticipated to remain in effect for many months to come. Therefore, the period of time the confiscatory rate levels will remain in effect is unreasonably long.

3. Without rate relief, Oliktok will suffer irreparable harm in that it will not have a reasonable opportunity to recover all of its just and reasonable costs during the period prior to establishment of revised permanent rates. Because of the general rule against retroactive ratemaking, Oliktok will have no future opportunity to recover the revenue not recovered during this period.

4. Making temporary rates refundable will protect Oliktok shippers if the Commission approves permanent rates that are lower than the temporary rates.

5. Oliktok's rate request is not frivolous or obviously without merit. It is supported by this filing, which includes information required under 3 AAC 48.275(a) for a rate adjustment, as well as the enclosed prepared direct testimony and exhibits.

IV. SECTION 275(a) PRESENTATION

Oliktok's 3 AAC 48.275(a) information is introduced and/or supported by the prepared direct testimonies of three witnesses, as follows:

1. Raj D. Choudhury. Mr. Choudhury is Vice President of Oliktok and is responsible for management of the Oliktok assets. Mr. Choudhury provides an overview of Oliktok's history, this rate filing, and the data that Oliktok provided to Mr. Wetmore for the calculation of Oliktok's proposed rates.

2. Erik G. Wetmore. Mr. Wetmore, an expert in the development of pipeline rates, presents the calculation of Oliktok's normalized test-year revenue requirement and the development of the rates needed to recover Oliktok's revenue requirement. Mr. Wetmore's testimony and its supporting exhibits address all of the information required by 3 AAC 48.275(a).

3. Bruce H. Fairchild. Dr. Fairchild, a cost of capital expert, develops the cost of capital elements (capital structure, cost of debt, and rate of return on equity) used by Mr. Wetmore in his calculation of Oliktok's normalized test-year revenue requirement.

Mr. Wetmore's prepared direct testimony sponsors the schedules required under 3 AAC 48.275(a). Most of those schedules are provided in Exhibit EGW-2 to Mr. Wetmore's testimony. As is explained in his testimony, Mr. Wetmore calculated Oliktok's revenue requirement for the normalized test year. Although all Oliktok throughput is currently delivered to only the Gas Spur Pipeline ("GSP") and Kuparuk River Unit ("KRU") delivery points, Oliktok's tariff also provides for deliveries to the Gas Hydrates Project ("GHP") delivery point.[3] For purposes of calculating at least a nominal rate for the GHP delivery point, Oliktok assumed a minimal GHP throughput of 1 MSCF per year.

Mr. Wetmore determined the revenue requirement for the three tariffed delivery points using the distance-related and non-distance-related cost methodology that has been used for decades under the original Oliktok Shippers Rate Agreement that was accepted by the Commission in Order No. P-84-003(11)/P-95-005(2) (as modified in TL17-334, filed October 12, 2001, and supplemented on December 16, 2001), and subsequent 2015 and 2024 Oliktok Settlement Agreements.[4] In addition, attached as Exhibit 2 to this filing is a summary of the methodology used to assign or allocate costs among Oliktok and its affiliates.

V. NOTIFICATION OF TARIFF FILING

Oliktok shippers are being notified of this filing electronically. A copy of this filing will be available for public inspection at the offices of the Oliktok Pipeline Company at 700 G Street, ATO 20-2052, Anchorage, Alaska 99501, Attn: Sandra Pierce (907) 265-6316 and on the internet at https://alaska.conocophillips.com/tariff/oliktok/

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[3] In Order No. P-25-009(1) (Dec. 18, 2025), the Commission granted Oliktok's application for a temporary suspension of gas transportation service to the Gas Hydrates Project delivery point. ASRC Consulting & Environmental Services, LLC, the prime contractor for the project, has notified Oliktok that it expects the project to reconnect to the Oliktok Pipeline Company and resume transportation service in 2027.

[4] Because Oliktok is not seeking a "rate redesign," but is simply applying the normalized revenue requirement to the historical Oliktok distance-related and non-distance-related cost methodology, there does not appear to be any requirement to file a cost-of-service study pursuant to 3 AAC 48.275(h) ("Section 275(h)"). To the extent a cost-of-service study is required, Oliktok submits that the rate design calculations shown on Exhibit EGW-2, Schedule 5, and the narrative discussion of the rate methodology in Mr. Wetmore's testimony satisfy the requirements of Section 275(h). If the Commission deems Section 275(h) to require anything greater than that, Oliktok requests that the Commission waive any such requirement.

VI. COMPLIANCE WITH 3 AAC 48.270(a)

Oliktok provides the following information:

3 AAC 48.270(a) – Name and return address of the filing utility:

Oliktok Pipeline Company
P.O. Box 100360
Anchorage, Alaska 99510-0360

3 AAC 48.270(a) – Name, return address, and electronic mail address of the utility's representative authorized to issue tariffs:

Raj D. Choudhury
Vice President
Oliktok Pipeline Company
P.O. Box 100360
Anchorage, Alaska 99510-0360
E-mail: Raj.Choudhury@conocophillips.com

3 AAC 48.270(a)(1) – List the tariff advice letter number:

See page 1.

3 AAC 48.270(a)(2) – Specify the statutes, regulations or commission order that the filing is made under:

See page 1.

3 AAC 48.270(a)(3) – List the tariff sheets, special contracts, agreements, or other documents required by commission order that are being filed:

See page 1.

3 AAC 48.270(a)(4) – Summarize the proposed tariff revisions, including an explanation about whether the filing proposes to implement rules, rates, or both:

The proposed tariff revisions will increase Oliktok's existing transportation rates.

3 AAC 48.270(a)(5) – Include a statement setting out whether the filing will impact any current customers and the estimated number of customers or shippers that will be affected:

The customers that will be affected by the proposed changes in rates are Oliktok's current shippers (five or fewer) receiving natural gas deliveries at the GSP and KRU delivery points and, once reconnected, gas deliveries at the GHP delivery point.

3 AAC 48.270(a)(6) – If applicable, include a request for the tariff filing to take effect before the end of the statutory notice period:

Oliktok does not request that approval of the proposed tariff revisions to existing transportation rates take effect before the expiration of the statutory notice period.

3 AAC 48.270(a)(7) – If applicable, include a request for interim approval:

See Section III above.

VII. CONCLUSION

Oliktok requests that the Commission grant permanent approval of the revisions to Oliktok's Tariff No. 4 reflected in the proposed Tariff Sheet No. 37 included in Exhibit 1. Should the Commission suspend TL57-334, Oliktok requests that those rates also be approved on a temporary and refundable basis effective August 1, 2026.

Sincerely yours,

KEMPPEL, HUFFMAN AND ELLIS, P.C.
Counsel for OLIKTOK PIPELINE COMPANY

By: /s/ *Dean D. Thompson*

Dean D. Thompson, ABA# 9810049
Emily M. Walker, ABA# 2211108
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Anchorage, Alaska 99503
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Enclosures

Exhibit 1

Schedule "A"
Rate
Gas Transportation Service

Application

This rate applies to regular Pipeline service for Gas as set forth in Carrier's tariff.

Rate

From	To	Rate Dollars and Cents per mscf*	
PBU (Skid 50)	Gas Hydrates Project	$0.914	I
PBU (Skid 50)	KRU (CPF #1)	$1.528	I
PBU (Skid 50)	Gas Spur Pipeline	$1.464	I

* mscf – Thousand standard cubic feet

Exhibit 2

EXHIBIT 2

OLIKTOK PIPELINE COMPANY
SUMMARY OF AFFILIATE COST ASSIGNMENT/ALLOCATION METHODOLOGY

Oliktok Pipeline Company ("Oliktok") is a wholly-owned subsidiary of ConocoPhillips Company. Oliktok does not have employees or facilities of its own. Instead, many of the services and facilities necessary to operate and maintain the Oliktok Pipeline are provided by its parent, ConocoPhillips Company, or its affiliates, including ConocoPhillips Alaska Pipelines, Inc. and ConocoPhillips Alaska Inc. The employees assigned to work for Oliktok also provide services to support other pipeline entities that are owned in whole or in part by ConocoPhillips Company (e.g., Alpine Transportation Company, Kuparuk Transportation Company, and ConocoPhillips Transportation Alaska Inc.).

Costs are allocated among ConocoPhillips' pipeline entities using "management fees." The categories of shared costs ("management fees") are as follows: Alaska allocations, Corporate allocations, Company compensation, insurance, and materials & supplies. The Alaska allocations from ConocoPhillips Alaska Inc. include costs without any mark-up for External Affairs, Facilities, Human Resources, and Information Technology. The Corporate allocations from ConocoPhillips Company include costs, without any mark-up, for company-wide services such as Accounting, Financial Services, Health and Safety, Human Resources, Legal, Tax, and Training.

All of the costs, except for insurance, are allocated by entity based on how employees estimate that they are spending their time. Insurance is allocated by entity based on relative gross Property, Plant, and Equipment ("PP&E") (before Depreciation, Depletion, and Amortization ("DD&A"). The annual amounts are approved in the respective pipeline budgets and then charged to the entities monthly.

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chair
Steve DeVries
Mark Johnston
John C. Springsteen
Julie C. Vogler

In the Matter of Revenue Requirement Study Designated as TL57-334 filed by OLIKTOK PIPELINE COMPANY for Natural Gas Transportation Service)

TL57-334

PREPARED DIRECT TESTIMONY OF RAJ D. CHOUDHURY ON BEHALF OF OLIKTOK PIPELINE COMPANY

Q.1. Please state your name, business address, and occupation and briefly describe your educational and professional background.

A.1. My name is Raj D. Choudhury. I am Vice President of Oliktok Pipeline Company ("Oliktok"), and I am responsible for management of the Oliktok asset. My office address is 700 G Street, P.O. Box 100360, Anchorage, Alaska 99501. My educational and professional background is set forth on Exhibit RDC-1.

Q.2. What is the purpose of your testimony in this proceeding?

A.2. The purpose of my testimony is to explain why Oliktok is submitting a rate filing, address certain pro forma adjustments, and identify other witnesses who are presenting direct testimony in support of Oliktok's rate filing. My testimony also describes the data that I supplied to Mr. Erik G. Wetmore for his use in preparing Oliktok's rate calculations.

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I. Overview of Oliktok's Rate Filing

Q.3. Please summarize Oliktok's rate filing.

A.3. Oliktok is filing TL57-334 to change its intrastate natural gas transportation rates to reflect current costs and throughput.

Q.4. Please briefly describe the history of the Oliktok pipeline and its regulation by the Commission.

A.4. In 1980, the Kuparuk Pipeline Company ("KPC") sought and obtained certification to operate as a pipeline carrier in connection with the planned construction of approximately 26 miles of 16-inch diameter pipeline to carry crude oil from the Kuparuk River Unit ("KRU") to Pump Station No. 1 of the Trans-Alaska Pipeline System ("TAPS"). *See* Order No. P-80-001(5) at 1. In 1982, KPC proposed to extend the pipeline approximately 8.7 miles from Central Production Facility ("CPF") No. 1, the original origin of the pipeline system, to CPF No. 2, and replace the existing 16-inch line from CPF No. 1 to TAPS with a 24-inch line to accommodate the additional volumes from CPF No. 2, with the 24-inch line to rest on the same vertical supports as the 16-inch line. *See* Order No. P-82-005(5), Appendix, Administrative Law Judge Recommended Decision at 6. The Commission granted this request. *Id.* at 7-8.

In 1984, Oliktok applied for a Certificate of Public Convenience and Necessity ("CPCN") to provide natural gas pipeline service by operating the 16-inch pipeline originally used by KPC for the transportation of crude oil. Order No. P-84-003(1). In 1985, Oliktok was granted a temporary CPCN and allowed to collect initial rates on a temporary basis. *Id.* at 6. In 1988, Oliktok filed a petition to discontinue service, as its

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shippers had indicated that natural gas transportation service was no longer needed. Order No. P-84-003(7). The request to discontinue service was granted in 1991, and Oliktok's temporary CPCN was suspended pending additional information regarding future use of the pipeline. Order Nos. P-84-003(8), P-84-003(9).

In 1995, Oliktok informed the Commission that it intended to ship natural gas liquids ("NGLs"), requested that the Commission make its current temporary CPCN permanent and change the scope of the CPCN to encompass the transportation of NGLs as well as natural gas. The Commission granted Oliktok a permanent CPCN for transportation of both natural gas and NGLs and approved initial tariff rules and rates for NGL transportation. Order No. U-84-003(11)/P-95-005(2).

From 1995 through 2013, Oliktok transported NGLs from the Prudhoe Bay Unit ("PBU") to KRU for injection into the KRU reservoir to enhance the recovery of marketable oil. Order No. P-13-013(2) at 4. In response to requests from shippers, Oliktok then sought approval to convert its service from the transportation of NGLs to the transportation of natural gas from the PBU to the KRU. Order No. P-13-013(2) at 4-6. The Commission approved the temporary discontinuance of NGL service in Order No. P-13-013(2).

The operator of the KRU ceased tendering natural gas for transportation beginning January 1, 2017. Order No. P-17-001(2) at 2. On August 15, 2017, the Commission authorized the temporary suspension of service on the Oliktok pipeline, subject to the requirement that Oliktok resume service upon receipt of tenders of natural gas or NGLs for shipment. Order No. P-17-001(2).

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The KRU owners subsequently indicated they intended to ship NGLs from the PBU to the KRU beginning on or about August 21, 2018. Oliktok filed Tariff Advice Letter No. TL46-334 for approval of a new NGL rate, setting forth rules and rates to be applicable to the transportation of both natural gas and NGLs, and seeking to simplify the process for approval of future changes in the product transported. On August 20, 2018, the Commission approved Tariff No. 4, but required Oliktok to request approval of natural gas transportation rates prior to offering such service. *See* Letter Order No. L1800364 at 1.

In 2021, the operator of the KRU requested that Oliktok begin shipping natural gas to the KRU on September 1, 2021. On July 1, 2021, Oliktok filed Tariff Advice Letter No. TL47-334, which sought to suspend NGL transportation service and establish inception rates for natural gas transportation. On August 25, 2021, the Commission approved the suspension of NGL transportation service and the natural gas inception rates. *See* Letter Order No. L2100300. In that letter order, the Commission required OPC to submit a 3 AAC 48.275(a) rate filing by July 1, 2026, based on a 2025 test year.

On March 30, 2022, Oliktok filed Tariff Advice Letter No. TL48-334, which sought to establish revised rates for natural gas transportation service. On April 22, 2022, the Commission approved the revised rates for natural gas transportation service. *See* Letter Order No. L2200137.

On January 6, 2023, Oliktok filed Tariff Advice Letter Nos. TL50-334 and TL51-334, which sought to establish initial and revised rates for natural gas transportation service. On February 23, 2023, the Commission approved the initial and revised rates for natural gas transportation service. *See* Letter Order No. L2300059.

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On May 16, 2024, the Commission accepted the Oliktok Settlement Agreement in Order No. P-24-007(2). The Settlement Agreement provides for annual rate revisions based on the Oliktok Settlement Methodology ("OSM"). Oliktok's 2025 OSM rates initially did not include a rate for the Gas Spur Pipeline delivery point, which is the delivery point for Oil Search (Alaska), LLC ("OSA"). On February 11, 2025, OSA informed Oliktok by e-mail that it planned to begin shipments over the Oliktok Pipeline in June 2025. For that reason, on April 10, 2025, Oliktok filed TL54-334 to revise its 2025 OSM rates to (1) include a rate for the OSA Gas Spur Pipeline delivery point and (2) reduce the rates for Oliktok's other delivery points to reflect a revenue-neutral allocation of costs for 2025, effective June 1, 2025. The Commission approved those updated rates in Letter Order No. L2500129 (May 16, 2025). Ultimately, OSA did not begin shipments over the Oliktok Pipeline until December 8, 2025, due to no fault of Oliktok.

On December 18, 2025, the Commission approved Oliktok's revised OSM rates for 2026 as proposed in TL56-334 with an effective date of January 1, 2026. *See* Letter Order No. L2500352 (Dec. 18, 2025).

Q.5. How is Oliktok justifying the rates set forth in its rate filings?

A.5. Oliktok's rates are supported by normalized test year revenue requirement and rate design analyses, as explained in detail in the prefiled direct testimony of Oliktok's witnesses.

Q.6. What other witnesses is Oliktok sponsoring in support of its rate filings?

A.6. Oliktok is sponsoring two witnesses in addition to me.

- First, Dr. Bruce H. Fairchild, an expert economist, presents the cost of capital for Oliktok.

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- Second, Mr. Erik G. Wetmore, an expert regulatory ratemaking consultant, presents Oliktok's revenue requirement and rate calculation using the data supplied to him by Dr. Fairchild and me.

II. Identification of Data Provided in Support of Rate Filings

Q.7. What data did you provide in support of Oliktok's rate filings?

A.7. Mr. Wetmore asked me to provide him with data used to develop operating expenses and rate base for the normalized test-year, as well as the throughput used to calculate tariff rates for the normalized test-year.

Q.8. Please describe the operating expense data that Mr. Wetmore asked you to provide to him.

A.8. Mr. Wetmore asked me to provide him with operating expenses, as reported in Oliktok's Annual Report filed with this Commission, for the year ending December 31, 2025. The test year expenses are provided in Exhibit RDC-2.

Q.9. Are there any pro forma adjustments to 2025 test year operating expenses?

A.9. Yes. As is explained in Mr. Wetmore's testimony, Oliktok proposes pro forma adjustments for rate case cost allowance, depreciation expense, and rate base.

Q.10. Please summarize the rate base data that Mr. Wetmore asked you to provide to him.

A.10. Mr. Wetmore asked me to provide him with carrier property in service ("CPIS") data and working capital data.

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Q.11. Please describe the CPIS data that Mr. Wetmore asked you to provide to him.

A.11. Mr. Wetmore requested that I provide him with the monthly amounts of CPIS placed in service or retired during 2025. The CPIS data that I provided to Mr. Wetmore is identified as Exhibit RDC-3.

Q.12. Please describe the working capital data that Mr. Wetmore asked you to provide to him.

A.12. Mr. Wetmore requested that I provide him with month-end balances of materials and supplies and prepayments for the period January 1, 2025, through December 31, 2025. The working capital data that I provided to Mr. Wetmore is identified as Exhibit RDC-4.

Q.13. Please describe the throughput data that Mr. Wetmore asked you to provide him.

A.13. Mr. Wetmore asked me to provide him with natural gas volumes transported during the historical 2025 test-year. For 2025, throughput volumes totaled 15,639 million cubic feet ("mmcf"), or about 43 million cubic feet per day ("mmcfd").

Q.14. Are there any pro forma adjustments to test year throughput volumes?

A.14. Yes. As is explained in Mr. Wetmore's testimony, Oliktok proposes adjustments to test year 2025 throughput volumes to reflect actual 2026 volumes through June 21, 2026, and shipper projections for the remainder of 2026.

Q.15. Does this conclude your prepared direct testimony?

A.15. Yes.

DATED this 1st day of July, 2026.

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Exhibit RDC-1

Raj Choudhury
700 G Street
P.O. Box 100360
Anchorage, Alaska 99510-0360
907-265-1618 (office)

Experience

	CONOCOPHILLIPS COMPANY
2025-present	Manager, Alaska Pipelines (Anchorage, AK)
2022-2024	Sr. Commercial Consultant, Alaska Transportation Asset (Anchorage, AK)
Jul-Dec 2021	Interim Manager, Alaska Transportation Asset (Anchorage, AK)
2016-2021	Sr. Commercial Consultant, Alaska Transportation Asset (Anchorage, AK)
2013-2016	Commercial Analyst Team Lead, Australia Commercial (Australia)
2008-2013	Sr. Commercial Consultant, Alaska Strategy & Portfolio Mgt. (Anchorage, AK)
	GENERAL MOTORS CORPORATION
2003-2008	Manager, Government Relations (Washington, DC)
1999-2003	Manager, Business Development (Germany)
	ATLANTIC RICHFIELD COMPANY
1996-1999	Sr. Planning Analyst, Corporate Planning (Los Angeles, CA)
1993-1996	Evaluation Analyst, Alaska Planning & Evaluation (Anchorage, AK)

Education

STANFORD UNIVERSITY

1993	Master of Arts, Food Research Institute

PRINCETON UNIVERSITY

1990	Bachelor of Arts, Mathematics

Exhibit RDC-2

Oliktok Pipeline Company
Test Year Operating Expenses, Pro Forma Adjustments, and Normalized Test-Year Operating Expenses
($000's)

Line No. (a)	Account No. (b)	Description (c)	Historical Test Year 2025 (d) 1/	Pro Forma Adjustment 1 (e) 2/	Normalized Test-Year (f) (d) thru (e)
		OPERATIONS			
1	300	Salaries and Wages	$862		$862
2	310	Supplies and Expenses	$85		$85
3	320	Outside Services	$286		$286
4	330	Fuel and Power	$1		$1
5	340	Oil Losses and Shorts	$0		$0
6	350	Rentals	$1,240		$1,240
7	390	Other Expenses	$0		$0
8		Total Operations	$2,474	$0	$2,474
		GENERAL			
9	500	Salaries and Wages	$0		$0
10	510	Supplies and Expenses	$0		$0
11	520	Outside Services	$0	$122	$122
12	530	Rentals	$158		$158
13	550	Pensions and Benefits	$1		$1
14	560	Insurance	$0		$0
15	570	Casualty and Other Losses	$0		$0
16	580	Pipeline Taxes	$821		$821
17	590	Other Expenses	$2,869		$2,869
18		Total General	$3,849	$122	$3,971
19		Grand Totals	$6,323	$122	$6,445

1/ Per Oliktok's 2025 Annual Report.
2/ Rate case cost allowance. See Wetmore direct testimony

Exhibit RDC-3

Oliktok Pipeline Company
Monthly Additions to and Retirements of
Carrier Property in Service
For the Year Ended December 31, 2025
($000's)

Line No. (a)	Description (b)	Jan (c)	Feb (d)	Mar (e)	Apr (f)	May (g)	Jun (h)	Jul (i)	Aug (j)	Sep (k)	Oct (l)	Nov (m)	Dec (n)	Total (o) (c) to (n)
	Additions to Carrier Property in Service:													
1	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Depreciable Property	$0	$0	$0	$0	$0	$0	$0	$0	$13,009	$0	$0	$0	$13,009
3	Additions to Carrier Property in Service	$0	$0	$0	$0	$0	$0	$0	$0	$13,009	$0	$0	$0	$13,009
	Retirements of Carrier Property in Service:													
4	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Depreciable Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Retirements of Carrier Property in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Exhibit RDC-4

Oliktok Pipeline Company
Working Capital
For the Year Ended December 31, 2025
(000's)

Line No. (a)	Date (b)	Materials and Supplies Account 17 (c)	Prepayment Account 18 (d)	Total Working Capital (e)
1	January-25	$275	$740	$1,015
2	February-25	$275	$673	$948
3	March-25	$248	$605	$853
4	April-25	$275	$538	$813
5	May-25	$275	$471	$746
6	June-25	$275	$814	$1,089
7	July-25	$275	$679	$954
8	August-25	$275	$543	$818
9	September-25	$275	$407	$682
10	October-25	$275	$271	$546
11	November-25	$313	$136	$448
12	December-25	$313	$807	$1,120

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: John M. Espindola, Chair
Steve DeVries
Mark Johnston
John C. Springsteen
Julie C. Vogler

In the Matter of Revenue Requirement Study Designated as TL57-334 filed by OLIKTOK PIPELINE COMPANY for Natural Gas Transportation Service) TL57-334

PREPARED DIRECT TESTIMONY OF BRUCE H. FAIRCHILD
ON BEHALF OF OLIKTOK PIPELINE COMPANY

I. Introduction

Q1. Please state your name and business address.

A1. My name is Bruce H. Fairchild. My business address is 3907 Red River, Austin, Texas 78751.

Q2. By whom are you employed and in what position?

A2. I am a principal in Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

II. Qualifications

Q3. Please describe your educational background, professional qualifications, and prior experience.

A3. I hold a BBA degree from Southern Methodist University and MBA and PhD degrees from the University of Texas at Austin. I am also a Certified Public Accountant. My previous employment includes working in the Controller's Department at Sears, Roebuck and

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Company and serving as Assistant Director of Economic Research at the Public Utility Commission of Texas ("PUCT"). I have also been on the business school faculties at the University of Colorado at Boulder and the University of Texas at Austin where I taught undergraduate and graduate courses in finance and accounting.

Q4. Please briefly describe your experience in rate-related matters.

A4. While at the PUCT, I assisted in managing a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems. I testified on behalf of the PUCT staff in numerous cases involving most major investor-owned and cooperative electric, telephone, and water/sewer utilities in the state regarding a variety of financial, accounting, and economic issues. Since forming FINCAP in 1979, I have participated in a wide range of analytical assignments involving rate-related matters on behalf of utilities, industrial consumers, municipalities, and regulatory commissions. I have also prepared and presented expert witness testimony before a number of regulatory authorities addressing revenue requirements, cost allocation, and rate design issues in the areas of gas distribution, gas and oil pipelines, electric, telephone, and water/sewer. I have been a frequent speaker at regulatory conferences and seminars and have published research concerning various regulatory issues. A resume that contains the details of my experience and qualifications is attached as Exhibit BHF-1, with Exhibit BHF-2 listing my prior testimony before regulatory agencies since leaving the PUCT.

III. Overview

Q5. What is the purpose of your testimony?

A5. My purpose here is to develop an overall rate of return for Oliktok Pipeline Company ("Oliktok") in connection with its request to revise its rates for natural gas transportation service. I also recommend allowance for funds used during construction ("AFUDC") rates.

Q6. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying.

A6. In preparing my analyses and testimony in this case, I utilized a variety of sources of information that would normally be relied upon by a person in my capacity. I am generally knowledgeable about pipelines from my prior work with many of the major intrastate natural gas transmission and distribution companies in Texas and elsewhere, and with pipelines in Alaska from having filed testimony on behalf of Oliktok in Dockets P-13-013, P-15-006, TL46-334, TL47-334, TL48-334, TL50-334, and TL51-334, the owners of the Trans-Alaska Pipeline System ("TAPS"), Kuparuk Transportation Company ("Kuparuk"), PTE Pipeline, LLC, and Pikka Transportation Company, LLC in a number of dockets. In connection with the present filing, I examined various data related to the Oliktok system, as well as the rate of return testimony and the Regulatory Commission of Alaska's ("Commission's") decisions in the last two decided cases involving TAPS intrastate rates, Dockets P-97-004 and P-03-004 ("Order 151"). I also reviewed information regarding capital markets generally and investor perceptions, requirements, and expectations for pipelines specifically. These sources, coupled with my experience in the fields of finance,

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accounting, economics, and utility regulation, enabled me to acquire a working knowledge of Oliktok and formed the basis for my analysis and conclusions.

Q7. Briefly describe the Oliktok system.

A7. The Oliktok system consists of a 16-inch pipeline that extends some 28 miles from the Prudhoe Bay field to the Kuparuk fields on Alaska's North Slope. Running approximately parallel to the Kuparuk pipeline, the Oliktok system has transported both natural gas liquids and natural gas, with the Oliktok system currently transporting natural gas. Oliktok is wholly owned by ConocoPhillips Company ("ConocoPhillips") and is financed entirely with equity capital.

Q8. What is the role of the rate of return in setting a pipeline's rates?

A8. The rate of return serves to compensate a pipeline's investors for the use of their capital to finance the plant and equipment used to provide service. Investors only commit money in anticipation of earning a return on their investment commensurate with that from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the U.S. Supreme Court cases of *Bluefield Water Works & Improvement Co.* (1923) and *Hope Natural Gas Co.* (1944), the rate of return allowed a pipeline must be sufficient to: 1) fairly compensate capital presently invested in the pipeline, 2) enable the pipeline to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the pipeline's financial integrity.

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Q9. How did you go about developing a fair rate of return for Oliktok?

A9. As indicated above, Oliktok is owned and financed by ConocoPhillips, which is the world's largest independent exploration and production ("E&P") company. Although the Oliktok system may be viewed as an integral part of ConocoPhillips's Alaskan E&P operations, in Order 151 the Commission rejected using the cost of capital to the oil and gas companies owning TAPS as the basis for determining the pipeline's rate of return. Instead, the Commission ordered that TAPS' rate of return be based on a pipeline proxy group:

> We rely on the gas and oil pipeline sample data, rather than oil pipeline data alone. As the Carriers' expert notes, the number of petroleum pipeline companies is quite small. Gas pipelines share many of the same business risks as oil pipelines, and can therefore provide a useful reference point. We find it reasonable to expect that investors would look to other publicly traded companies, engaged in similar affairs, for guidance.

Order 151 at 137 (footnotes omitted). In an effort to minimize the cost and controversy surrounding rate of return in this case, I followed the Commission's rate of return methodology for oil pipelines described in Order 151, updated to reflect changes in industry participants, capital markets conditions, and information generally available to investors, to develop my recommended rate of return for Oliktok.

IV. <u>Summary of Conclusions</u>

Q10. What rate of return do you recommend be used for present purposes?

A10. I recommend an overall rate of return for Oliktok of 8.20%, which is calculated on Schedule 1, Exhibit BHF-3. As shown there, this rate of return is based on a capital

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structure consisting of 55.34% debt and 44.66% equity, a cost of debt of 5.13%, and a return on equity of 12.00%.

Q11. How did you arrive at your recommended capital structure ratios?

A11. The 55.34% debt and 44.66% equity reflect the average capital structure ratios at March 31, 2026, of a proxy group consisting of ten publicly traded gas and oil pipelines (Schedule 3, Exhibit BHF-3).

Q12. How did you determine the cost of debt?

A12. The 5.13% cost of debt is the average embedded cost of debt at March 31, 2026, for the same proxy group of ten pipelines (Schedule 4, Exhibit BHF-3).

Q13. How did you arrive at the 12.00% return on equity?

A13. Following the Commission's Order 151, four methods were used to estimate the cost of equity -- the discounted cash flow ("DCF") model, the equity risk premium ("ERP") method, the empirical capital asset pricing model ("ECAPM"), and the comparable earnings method ("CEM"). Applications of the DCF model, ERP method, ECAPM, and CEM to the proxy group of pipelines produce cost of equity estimates of 11.72%, 10.95%, 11.70%, and 13.61%, respectively; the arithmetic average of these estimates is 12.00% (Schedule 5, Exhibit BHF-3).

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V. Capital Structure and Cost of Debt

Q14. What is the purpose of this section?

A14. This section discusses the implications of capital structure on risk and investors' required rates of return and develops a proxy group of pipelines for use in determining an overall rate of return for Oliktok. Based on this proxy group, this section then calculates capital structure ratios and a cost of debt for Oliktok.

1. Capital Structure

Q15. What is the role of capital structure in setting a pipeline's rate of return?

A15. Capital structure reflects the mix of capital – debt and equity – used to finance a firm's assets. The proportions of a pipeline's total capitalization attributable to each source of capital are used to weight the cost of debt and rate of return on equity in calculating an overall rate of return.

Q16. Why does this weighting matter?

A16. The capital structure ratios determine how much weight is given to a particular source of capital and, because the costs of debt and the rate of return on equity are not the same, this affects the weighted average cost, or overall rate of return, of all sources of capital.

Q17. How does the use of greater amounts of debt affect the rates of return required by investors?

A17. A higher debt ratio, or lower equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive its contractual payments.

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This, in turn, increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest for their risk bearing. From shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that remains. In accordance with the fundamental risk-return trade-off principle to be discussed later, shareholders require a correspondingly higher rate of return to compensate them for bearing the greater financial risk associated with a lower equity ratio.

Q18. How did you determine capital structure ratios for present purposes?

A18. As noted earlier, Oliktok is financed entirely with equity capital contributions from ConocoPhillips, and ConocoPhillips' capital structure reflects that it is primarily engaged in E&P activities. In Order 151, the Commission stated:

> We determine the appropriate capital structure for a stand-alone TAPS with reference to the capitalization of a pipeline sample. ... (W)e use book value to determine benchmark capitalization of the proxy pipeline companies.

Order 151 at 137. Consistent with the Commission's decision, I developed capital structure ratios for use in determining a rate of return for Oliktok based on the capitalizations recorded on the books of a proxy group of pipelines.

Q19. How did you arrive at your proxy group of pipelines?

A19. A proxy group serves as a representative sample of firms having risks comparable to the activity at issue and from which relevant financial data can be developed. Accordingly, I selected a proxy group by identifying firms regarded by the investment community as being primarily gas and oil pipelines and for which the data required to implement the Commission's method of determining a rate of return are available.

Q20. Please describe your selection process.

A20. I began with the 22 firms included in *The Value Line Investment Survey's* ("Value Line") Oil/Gas Distribution and Pipeline MLPs industries (May 22, 2026). Value Line is used as the source of firms from which to select the pipeline proxy group because Value Line data are used to implement the Commission's Order No. 151 methodology and Value Line is widely available to investors and generally accepted for ratemaking purposes. As summarized on Schedule 2, Exhibit BHF-3, I exclude those companies primarily engaged in alternative fuels, marketing, non-pipeline, and Canadian operations, as well as those firms not having representative or sufficient data relative to the Commission's method of determining a rate of return. This selection process results in a proxy group consisting of the following ten pipelines:

DT Midstream
Enbridge, Inc.
Energy Transfer LP
Enterprise Products Partners
Kinder Morgan, Inc.
MPLX LP
ONEOK, Inc.
Plains All American Pipeline
TC Energy Corp.
Williams Cos.

Q21. What capital structure ratios do these pipelines maintain?

A21. Schedule 3, Exhibit BHF-3, displays the capital structure ratios for each of the ten pipelines in the proxy group at December 31, 2023, 2024, and 2025, and March 31, 2026. The

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average debt and equity ratios of the proxy group have been relatively steady over these time periods. Accordingly, I use the proxy group's most recent average capital structure ratios at March 31, 2026, of 55.34% debt and 44.66% equity to develop the rate of return for Oliktok.

2. Cost of Debt

Q22. How did you determine a cost to apply to the 55.34% debt component of the capital structure?

A22. Because Oliktok is financed entirely with equity capital, it has no debt. Moreover, in Order 151, the Commission stated: "[W]e look to the actual embedded proxy company cost of debt." Order 151 at 140. Therefore, I calculate the average embedded cost of debt at March 31, 2026, for the ten pipelines comprising the proxy group.

Q23. What is this average cost of debt?

A23. As shown on Schedule 4, Exhibit BHF-3, the average embedded cost of debt for the ten pipelines in the proxy group is 5.13%.

VI. Return on Equity

Q24. How did you arrive at a return on equity to apply to the 44.66% equity component of the capital structure?

A24. In Order 151, the Commission stated:

> We base our rate of return findings primarily upon Tesoro's witnesses' recommendation. Tesoro sponsors multiple methods because it believes investors rely on the widest possible information available. We agree with Tesoro that investors are aware of all the various traditional cost of common

> equity models discussed in financial literature. Absent good reason for believing that investors weight the results of one method more heavily than another in their assessment of an appropriate rate of return, it is reasonable to hold that investors ascribe weight to them all.

Order 151 at 144-45. In turn, I reviewed the testimony and workpapers of Tesoro's witness (Mr. Frank J. Hanley) in Dockets P-97-004 and P-03-004 and applied his various methodologies, as modified by the Commission, to the proxy group of pipelines using current data and information.

Q25. Briefly summarize the results of applying the methods ordered in Docket P-97-004.

A25. As indicated earlier, the Commission relied on four methods to determine a return on equity – the DCF model, the ERP method, the ECAPM, and the CEM. As shown on Schedule 5, Exhibit BHF-3, application of the DCF model, ERP method, ECAPM, and CEM to the proxy group of pipelines produced cost of equity estimates of 11.72%, 10.95%, 11.70%, and 13.61%, respectively, with an average of 12.00%.

1. Discounted Cash Flow Model

Q26. How are DCF models used to estimate the cost of equity?

A26. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market valuation process which led to the price investors are willing to pay for a share of a company's stock. It is predicated on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each share of stock is adjusted by the market so that investors are adequately compensated for the risks to which they are exposed. Therefore, we can

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look to the market to determine what investors believe a share of stock is worth, and by estimating the cash flows they expect to receive from the stock in the way of future dividends and stock price, their required rate of return can be mathematically imputed. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, investors presumably used in arriving at that price.

Q27. What market valuation process underlies DCF models?

A27. DCF models are derived from a theory of valuation which posits that the price of a share of stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+K_e)^1} + \frac{D_2}{(1+K_e)^2} + \cdots + \frac{D_t}{(1+K_e)^t} + \frac{P_t}{(1+K_e)^t}$$

where: P_0 = Current price per share;
P_t = Future price per share in period t;
D_t = Expected dividend per share in period t;
K_e = Cost of equity.

Q28. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A28. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. Given a number of assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{K_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity ("K_e") can be isolated by rearranging terms:

$$K_e = \frac{D_1}{P_0} + g$$

The constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q29. How was the DCF model applied in Docket P-97-004?

A29. The DCF cost of equity adopted in Order 151 was calculated as the average of: 1) a "single-stage" growth DCF cost of equity estimate, and 2) the average of two "two-stage" growth DCF cost of equity estimates. This is shown in Schedule 6, Exhibit BHF-3.

Q30. Is there anything common to all three of the DCF cost of equity estimates?

A30. Yes. All three DCF applications use a current dividend yield as the starting point. The average dividend yields for each firm in the pipeline group for four time periods – May 2026 (Spot), March 2026 – May 2026 (Last 3 Months), December 2026 – May 2026 (Last 6 Months), and June 2025 – May 2026 (Last 12 Months) – are developed in Schedule 7,

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Exhibit BHF-3. As in Docket P-97-004, these are then combined to obtain an average current dividend yield for the proxy group of 5.25%.

Q31. Please describe the growth rate in the single-stage DCF model application.

A31. The growth rate in the single-stage DCF model application is based on two estimates of earnings growth by investment analysts for each pipeline in the proxy group. As developed in Schedule 8, Exhibit BHF-3, the earnings per share growth rate between 2023-25 and 2029-31 projected by Value Line and the consensus 5-year I/B/E/S earnings growth rate are combined to obtain a single-stage growth rate for each pipeline, with the average for the proxy group (after excluding one anomalously high growth rate) being 7.42%.

Q32. How was this growth rate combined with the current dividend yield to calculate the single-stage DCF cost of equity estimate for the proxy group?

A32. Referring to the "Single-Stage Growth" column on Schedule 6, Exhibit BHF-3, the first step is to convert the average current dividend yield for the proxy group to an expected dividend yield over the coming year (*i.e.*, D_1/P_0 in the DCF formula). This is accomplished by increasing the current dividend yield of 5.25% from Schedule 7, Exhibit BHF-3, by 3.71% (*i.e.*, one-half of the 7.42% growth rate from Schedule 8, Exhibit BHF-3), which produces an expected dividend yield of 5.44%. Adding to this the 7.42% growth rate from Schedule 8, Exhibit BHF-3, produces a single-stage growth DCF cost of equity estimate of 12.86%.

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Q33. Please describe the growth rate in the first two-stage DCF model application.

A33. The growth rate in the first two-stage DCF model application is essentially derived from a 20-year version of the general form of the DCF model described earlier. As shown on Schedule 9, Exhibit BHF-3, for each firm in the proxy group, its current dividend per share (*i.e.*, annualized most recent dividend) is increased for the first five years by its average "single-stage" projected growth rate from Schedule 8, Exhibit BHF-3. For the next 15 years, the dividend is increased by 3.88%, which is the average long-term growth rate for the U.S. Gross Domestic Product ("GDP") projected by S&P Capital IQ ("S&P Global"), the Energy Information Administration ("EIA"), and the Social Security Administration ("SSA") between 2032 and 2046. The resulting 2046 dividend is then compared to the 2026 dividend, with the average annual compound rate of growth over the 20-year period being the two-stage growth rate in this application of the DCF model. As shown in the lower right-hand corner of Schedule 9, Exhibit BHF-3, the two-stage growth rate for the proxy group of pipelines using this method averages 5.07%.

Q34. What DCF cost of equity estimate was indicated by this growth rate?

A34. Referring to the middle column on Schedule 6, Exhibit BHF-3, the proxy group's current dividend yield of 5.25% is again increased by 3.71% (*i.e.*, one-half of the first-stage growth rate of 7.42%) to produce an expected dividend yield of 5.44%. Adding this to the average 5.07% two-stage growth rate from Schedule 9, Exhibit BHF-3, results in a DCF cost of equity estimate using this two-stage growth rate method of 10.52%.

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Q35. Please describe the second two-stage growth DCF application.

A35. The second two-stage growth DCF application uses the method prescribed by the Federal Energy Regulatory Commission ("FERC") to calculate a DCF growth rate for interstate oil and gas pipelines. Refined in its *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines* (May 21, 2020), the FERC method calculates a two-stage growth rate by weighting each firm's I/B/E/S consensus growth rate two-thirds and a long-term economy-wide growth rate one-third. For pipelines organized as C corporations, this economy-wide growth rate is the average of the GDP growth rate beginning in 2030 indicated by S&P Global, EIA, and SSA data, and for pipelines organized as master limited partnerships ("MLPs"), it is one-half of this average long-term GDP growth rate.

Q36. What DCF cost of equity estimate was produced using the FERC two-stage growth rate?

A36. As shown on Schedule 10, Exhibit BHF-3, weighting each pipeline's I/B/E/S growth rate two-thirds and the long-term GDP growth rate corresponding to its organizational form one-third produces an average two-stage growth rate for the proxy group (again excluding one anomalously high growth rate) using the FERC method of 5.25%. Carrying this to the last column on Schedule 6, Exhibit BHF-3, increasing the proxy group's current dividend yield of 5.25% by 2.63% (*i.e.*, one-half of the average IBES growth rate of 5.25% shown on Schedule 10, Exhibit BHF-3) results in an expected dividend yield of 5.39%. Adding this expected dividend yield to the 5.25% FERC two-stage growth rate produces a DCF cost of equity estimate of 10.64%.

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Q37. What is the DCF cost of equity when the three estimates described above were combined as in Order 151?

A37. Referring again to Schedule 6, Exhibit BHF-3, a two-stage growth DCF cost of equity estimate of 10.58% is first calculated by averaging the 10.52% based on the 20-year version of the general form of the DCF model and the 10.64% based on the FERC form of the DCF model. This two-stage DCF cost of equity estimate is then averaged with the 12.68% single-stage growth DCF cost of equity estimate to calculate a DCF cost of equity of 11.72%.

2. <u>Equity Risk Premium Method</u>

Q38. What fundamental economic principle underlies the ERP method?

A38. The ERP method is predicated on the notion that investors are risk averse and will willingly accept additional risk only if they expect to be compensated for bearing that risk. Since all assets compete with each other for investors' funds, riskier assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them. Given this risk-return tradeoff, the minimum required rate of return ("k") from an asset ("i") can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and
RP_I = Risk premium required to hold more risky asset i.

The cost of equity is estimated using the ERP method by determining the additional return investors require to forgo the relative safety of a bond and bear the greater risks associated with stock, and then adding this equity risk premium to the current yield on bonds.

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Q39. How was the cost of equity estimated using the ERP method adopted in Docket P-97-004?

A39. As reflected in Schedule 11, Exhibit BHF-3, the ERP cost of equity for the proxy group is calculated as the sum of a prospective yield on triple-B public utility bonds plus an average equity risk premium.

Q40. Why was the yield on triple-B utility bonds used as the base interest rate in applying the ERP method?

A40. As shown in footnote (b) on Schedule 12, Exhibit BHF-3, the pipelines in the proxy group are on average rated triple-B by Moody's Investors Service ("Moody's") and Standard & Poor's Corporation ("S&P"). Therefore, the expected yield on corresponding triple-B public utility bonds served as the relevant benchmark for calculating the cost of equity for the proxy group using the ERP method.

Q41. How was the prospective yield on triple-B public utility bonds determined?

A41. Because there is not a widely published forecast of interest rates on triple-B public utility bonds, a prospective triple-B yield is estimated by adjusting projected triple-A corporate bond rates using the same methodology as in Docket P-97-004. As developed in the upper portion of Schedule 12, Exhibit BHF-3, *Blue Chip Financial Forecasts* projects the yield on triple-A corporate bonds to average 5.60% during the first quarter of 2026 and 5.50% in the third and fourth quarters of 2026 and first three quarters of 2027. As also shown on Schedule 12, Exhibit BHF-3, between June 2025 and May 2026, the spread between yields on triple-B public utility bonds and triple-A corporate bonds averaged 0.53%, 0.53%, and 0.57% over the last three-, six-, and twelve-month periods, respectively. The average of

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these spreads is 0.54%, which when added to the projected yield on triple-A corporate bonds of 5.52% indicates a prospective yield on triple-B utility bonds of 6.06%.

Q42. How was the average equity risk premium determined?

A42. The equity risk premium used in the ERP method adopted in Docket P-97-004 is an average of two risk premium estimates. The first of these is a beta-adjusted total market risk premium, with the second being an equity risk premium based on the S&P Public Utilities Index.

Q43. Please describe the beta-adjusted total market risk premium estimate.

A43. The beta-adjusted total market risk premium is developed in Schedule 13 of Exhibit BHF-3. As shown in the upper portion of that schedule, it is actually based on two market equity risk premium estimates – one historical and the other forecasted.

Q44. Please describe the historical market equity risk premium estimate.

A44. The historical market equity risk premium estimate is based on realized rate of return data originally reported in *Market Results for Stocks, Bonds, Bills and Inflation*, and variously published by Ibbotson Associates, Morningstar, Duff & Phelps, and Kroll since. As shown in the upper portion of Schedule 13, Exhibit BHF-3, over the 100-year period 1926 to 2025, the annual realized rate of return from holding the S&P 500 index has averaged 12.23%, while the annual realized rate of return on Long-term Corporate Bonds has averaged 5.96%. The difference between these rates of return implies a market equity risk premium based on historical experience of 6.27%.

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Q45. Please describe the forecasted market equity risk premium estimate.

A45. The forecasted market equity risk premium estimate is based on Value Line's projections of annual price appreciation 3-5 years hence plus the dividend yield for the approximately 1,700 firms that it follows. In footnote (c) of Schedule 13, Exhibit BHF-3, Value Line's median price appreciation potential at the end of each month between June 2025 and May 2026 and corresponding dividend yields are converted to estimated annual rates of return. Combining the June 12, 2026, estimate of 11.83% with the previous 3-, 6-, and 12-month averages of 12.42%, 11.47%, and 11.37%, respectively, produced an average forecasted market rate of return of 11.77%. Subtracting the 5.52% prospective yield on triple-A corporate bonds shown on Schedule 12, Exhibit BHF-3, produces the forecasted market equity risk premium estimate of 6.26% shown in the middle of Schedule 13, Exhibit BHF-3.

Q46. How were the historical and forecasted equity risk premium estimates used to arrive at the beta-adjusted market equity risk premium?

A46. On Schedule 13, Exhibit BHF-3, the 6.27% historical market equity risk premium estimate and the 6.26% forecasted market equity risk premium estimate are averaged, resulting in a market equity risk premium of 6.26%. This equity risk premium for the market as a whole is then adjusted to reflect the relative risk of the proxy group using the pipelines' average beta, which is a risk measure that will be described subsequently in connection with the ECAPM. Multiplying the 6.26% market equity risk premium by the proxy group's average beta of 0.94 (developed in footnote (d) of Schedule 13, Exhibit BHF-3) produces the beta-adjusted market equity risk premium of 5.89%.

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Q47. Having explained the beta-adjusted market equity risk premium, next describe the second equity risk premium based on the S&P Public Utilities index.

A47. The equity risk premium based on the S&P Public Utilities index is developed in Schedule 14, Exhibit BHF-3. As shown in footnote (b) of Schedule 14, Exhibit BHF-3, the annual rate of return for holding the S&P Public Utilities index between 1928 and 2025 has averaged 10.79%. Also shown there is that the average annual rate of return from Long-term Corporate Bonds over this same period has been 5.92%. The implied equity risk premium of 4.86% (*i.e.*, 10.79% minus 5.92%) must be adjusted, however, to reflect the difference between yields on corporate versus public utility bonds. Between 1928 and 2025 the yield on triple-B utility bonds averaged 95 basis points higher than that on high-grade corporate bonds (*i.e.*, 6.75% versus 5.79%). Reducing the implied 4.68% equity risk premium by 95 basis points results in an equity risk premium for utilities of 3.91% above the yield on triple-B public utility bonds.

Q48. Briefly summarize the cost of equity produced by the ERP method adopted in Docket P-97-004?

A48. As shown on Schedule 11, Exhibit BHF-3, the cost of equity for the proxy group of pipelines is calculated under the ERP method by adding an equity risk premium to the prospective yield on triple-B public utility bonds. Projected triple-A corporate bond yields are adjusted based on recent relationships to develop a prospective triple-B public utility bond yield of 6.06%. Meanwhile, an equity risk premium for the proxy group of 4.90% is developed by averaging a beta-adjusted total market equity risk premium of 5.89% and an equity risk premium based on the S&P Utilities Index of 3.91%. Combining the 6.06%

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bond yield and 4.92% equity risk premium results in an ERP cost of equity for the proxy group of 10.95%.

3. **Empirical Capital Asset Pricing Model**

Q49. What is the capital asset pricing model ("CAPM")?

A49. The CAPM is a theory of market equilibrium that serves as the basis for current financial education and management. Under the CAPM, investors are assumed to be fully diversified, so that the relevant risk of an individual asset (*e.g.*, stock) is its volatility relative to the market as a whole, which is measured using a "beta" coefficient. Beta reflects the tendency of a stock's price to follow changes in the market, with stocks having a beta less than 1.00 being considered less risky and stocks with a beta greater than 1.00 being regarded as more risky. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j (R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free interest rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

Q50. How does the CAPM differ from the ECAPM?

A50. Empirical analyses of the CAPM have found that actual experience does not correspond exactly with the theory. Therefore, an ECAPM has been developed that adjusts the equity risk premium in the CAPM in order to approximate empirical market data and allow for better cost of equity estimates. The ECAPM adopted by the Commission in Order 151, which is the most commonly accepted form of ECAPM, adds to a risk-free interest rate an

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equity risk premium calculated as an unadjusted market equity risk premium weighted 25% and a beta-adjusted market equity risk premium weighted 75%.

Q51. How did you arrive at a prospective risk-free interest rate?

A51. As shown on Schedule 15, Exhibit BHF-3, the average yield projected by *Blue Chip Financial Forecasts* on Long-term Treasury Bonds during each of the last three quarters of 2026 and first three quarters of 2027 of 4.90% are averaged to develop a prospective risk-free interest rate of 4.90%.

Q52. How is the market equity risk premium calculated?

A52. Similar to the calculation of the beta-adjusted total market risk premium in the ERP method, the market equity risk premium is also based on two market equity risk premium estimates -- one historical and the other forecasted.

Q53. Please describe the historical market equity risk premium estimate.

A53. The historical market equity risk premium estimate is again based on realized rate of return data presently published by Kroll. For the ECAPM, however, the equity risk premium is calculated by subtracting from the 12.23% average rate of return on the S&P 500 index over the period 1926-2025 the average income return on Long-term Government Bonds of 4.86%. This produces a historical market equity risk premium estimate of 7.37%, which is shown in the upper portion of footnote (b) on Schedule 15, Exhibit BHF-3.

Q54. Please describe the forecasted market equity risk premium estimate.

A54. As with the beta-adjusted total market risk premium in the ERP method, the forecasted market equity risk premium estimate is also based on Value Line's forecast of annual price appreciation 3-5 years hence plus dividend yield. Subtracting the 4.90% prospective yield on Long-term Treasury Bonds from the average forecasted market rate of return of 11.77% developed on Schedule 13, Exhibit BHF-3, produces a forecasted market equity risk premium estimate of 6.87%, which is also shown in footnote (b) on Schedule 15, Exhibit BHF-3.

Q55. How were these historical and estimated equity risk premium estimates used to arrive at the market equity risk premium?

A55. As shown at the bottom of footnote (b) on Schedule 15, Exhibit BHF-3, the 7.37% historical market equity risk premium estimate and the 6.87% forecasted market equity risk premium estimate are averaged, resulting in a market equity risk premium of 7.12%.

Q56. How is this market equity risk premium used in the ECAPM?

A56. As explained earlier, the equity risk premium under the ECAPM is calculated as 25% of the unadjusted market equity risk premium plus 75% of the beta-adjusted market equity risk premium. Therefore, the ECAPM equity risk premium is calculated as 25% times 7.12% plus 75% times 6.69% (*i.e.*, 7.12% times the proxy group's average beta of 0.94), for a market equity risk premium of 6.80% (Schedule 15, Exhibit BHF-3).

Q57. Briefly summarize the cost of equity for the proxy group of pipelines using the ECAPM?

A57. As shown on Schedule 15, Exhibit BHF-3, summing the prospective risk-free interest rate of 4.90% with the ECAPM equity risk premium of 6.80% produces an ECAPM cost of equity for the proxy group of 11.70%.

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4. <u>Comparable Earnings Method</u>

Q58. What is the CEM?

A58. Rather than estimating investors' required rate of return at the capital market level, the CEM looks to the rates of return on book equity being earned by other firms. This method provides an indication of the level of earnings needed in order to offer a competitive return on investment, to attract capital on reasonable terms, and to maintain the firm's financial integrity.

Q59. Please describe how the CEM was applied in Docket P-97-004.

A59. In Docket P-97-004, the CEM was applied by selecting a group of unregulated companies having similar risk to the proxy group and examining their median projected rate of return on book equity. Tesoro's witness Mr. Hanley identified four criteria used to select the group of comparable risk firms:

- They must be domestic, non-price regulated companies (*i.e.*, non-utilities).
- They must have a meaningful projected five-year rate of return on net worth or partner's capital of less than 20%.
- Their betas must lie within plus or minus two standard deviations of the unadjusted betas.
- Their standard errors of the regressions must lie within plus or minus two standard deviations of the standard errors of the regressions of the proxy group. *See* Testimony of Frank J. Hanley, Docket No. P-97-4, Exhibit FJH-T at 49-50.

Q60. What was the purpose of the last two criteria?

A60. The last two criteria were designed to identify firms having market risk similar to the proxy group, which Mr. Hanley summarized in his testimony in Docket P-97-004 as follows:

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> (C)ompanies which have similar betas and similar standard errors of the regressions have similar total investment risk (the sum of non-diversifiable risk measured by beta and diversifiable risk measured by similar standard errors) because those statistics result from regression analyses of market prices which reflect investors' perceptions of all risks in accord with the EMH [efficient market hypothesis].

Testimony of Frank J. Hanley, Docket No. P-97-004, Exhibit FJH-T at 50. A review of Exhibit FJH-11 revealed that these criteria were applied in implementing the CEM through an analysis of information contained in a proprietary Value Line data base.

Q61. How did you implement the CEM?

A61. I do not, and assume that most investors do not, have access to the proprietary Value Line data base relied on by Mr. Hanley in Docket P-97-004. However, it is my understanding that the CEM in Docket P-97-004 was intended to examine the returns of unregulated companies that have total market risk (*i.e.*, both systematic and diversifiable) similar to the pipeline proxy group. One of Value Line's published risk measures -- the Price Stability Index -- is a measure of a stock's relative total market risk. Therefore, to implement the CEM, I selected the 66 domestic firms in Value Line having a Price Stability Index of 85, which is closest to the average Price Stability Index of the pipeline proxy group (footnote (b) of Schedule 16, Exhibit BHF-3). I then excluded from the Value Line group five regulated firms (including two in the proxy group) and the 37 firms that had projected 2029-2031 returns on equity equal to or greater than 20%, as was done in Docket P-97-004.

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Q62. What were the results of applying the CEM?

A62. As shown in the upper portion of Schedule 16, Exhibit BHF-3, this application of the CEM, which I believe is consistent with that adopted in Order 151 but uses publicly available information, results in a group of 37 unregulated companies having a median projected return on equity of 13.61%.

5. <u>Summary of Return on Equity</u>

Q63. Please summarize your return on equity analysis.

A63. Following the Commission's Order 151, four methods are used to estimate the cost of equity for Oliktok -- the DCF model, the ERP method, the ECAPM, and the CEM. I attempted to apply these methods to the proxy group in the manner that was approved in Order 151, updated for changes in industry participants and current capital market conditions and using information generally available to investors. As described above, applying the DCF model, ERP method, ECAPM, and CEM to the proxy group of gas and oil pipelines produces cost of equity estimates of 11.72%, 10.95%, 11.70%, and 13.61%, respectively. The arithmetic average of these estimates is 12.00% (Schedule 5, Exhibit BHF-3).

Q64. Have you evaluated the reasonableness of this cost of equity estimate based on the Commission's Order 151 methodology?

A64. Yes. There are two factors in the Commission's Order 151 methodology that materially affect the cost of equity estimates. The first is the assumption in two of the three DCF applications that investors expect security analyst long-term growth projections for the

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proxy pipelines to revert to that of the U.S. economy as a whole. The second is the sole use of Value Line's forecasted 3-5 year average return to measure investors' required rate of return from the market in the applications of the ERP and ECAPM.

Q65. What is wrong with the assumption that investors expect the long-term growth of pipelines to revert to projected GDP growth?

A65. There is no evidence to suggest that growth for each of the pipelines in the proxy group will converge to GDP growth over time, or that investors have incorporated this assumption into stock prices. With the exception of DT Midstream, all of the proxy pipelines have been in business for decades and are mature companies. These companies have already reached a "steady-state" where their future growth is expected to remain fairly stable. Accordingly, projected growth rates by security analysts are generally regarded as the most reliable guide to investors' long-term growth expectations, not a hypothesized two-stage growth rate that assumes the growth of all the pipelines will fall to that of the economy as a whole. Thus, the DCF model that best describes the valuation of the proxy pipelines is the constant growth form that uses company-specific analysts' growth rates projections, not a two-stage DCF model that erroneously assumes investors expect that the longer-term growth of all companies will be equal to GDP growth of less than four percent.

Q66. What about the sole use of *Value Line's* forecasted 3-5 year average return to measure investors' required rate of return from the market?

A66. While *Value Line's* forecasted 3-5 year average return provides one estimate of the required return from the market as a whole, it is only a single source of information. A more robust and commonly accepted method to estimate the market cost of equity is to apply the DCF

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model to a large group of firms using multiple security analyst growth projections. This is similar to how the market risk premium in the CAPM is calculated under the Federal Energy Regulatory Commission's May 21, 2020, *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*.

Q67. Can you illustrate why multiple sources are preferable to a single source of data to estimate the market cost of equity?

A67. Yes. I estimated the cost of equity for the market by applying the DCF model to the firms in the S&P 500 paying cash dividends using the projected earnings growth rates published by Value Line, I/B/E/S, and Zacks Investment Research ("Zacks"). Companies with growth rates below zero and above 20% were excluded, and the dividend yield and growth rate of each firm was weighted by its proportionate share of total market value. This produces the following cost of equity estimates for the market as a whole:

Projected Growth Rate	**Cost of Equity**
Value Line	11.88%
I/B/E/S	14.06%
Zacks	14.08%
Average	**13.44%**

Notably, the estimated market cost of equity of 11.88% using Value Line growth rates is similar to the 11.77% using its forecasted 3-5 year average return. However, both market cost of equity estimates based only on Value Line data are appreciably different from the 14.06% and 14.08% estimates based on the consensus earnings growth rate projections of I/B/E/S and Zacks, respectively. Consistent with the Commission ascribing weight to various methods to estimate the cost of equity in its Order 151 methodology, the 13.44%

average of the three market cost of equity estimates is presumably more reliable than an estimate based on a single source.

Q67. If the two-stage DCF cost of equity estimates using GDP growth were eliminated, and Value Line's forecasted 3-5 year average return of 11.77% were replaced in the ERP and ECAPM with the 13.44% average market cost of equity estimate developed above, what would be the resulting ROE for the pipeline group?

A67. As shown below, making just these two modifications to the Commission's Order 151 methodology would increase the estimated cost of equity to pipelines from 12.00% to 12.58%:

Cost of Equity Estimate	**Cost of Equity**
Discounted Cash Flow Model	12.86%
Risk Premium Model	11.35%
Capital Asset Pricing Model	12.50%
Comparable Earnings Method	13.61%
Average	**12.58%**

Q68. Are you recommending an ROE that incorporates these two modifications to the Commission's Order 151 methodology?

A68. No. As noted earlier, in an effort to minimize the cost and controversy surrounding rate of return in this case, my recommended ROE of 12.00% for Oliktok follows strictly the Commission's Order 151 methodology. The purpose of the above analyses is simply to demonstrate that fully supported modifications to the Commission's Order 151 methodology would produce a higher cost of equity estimate for oil and gas pipelines. Accordingly, my recommended ROE of 12.00% for Oliktok is reasonable, if not understated.

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VII. Overall Rate of Return

Q69. What overall rate of return do you recommend be used for present purposes?

A69. I recommend an overall rate of return for Oliktok of 8.20%. As developed in Schedule 1, Exhibit BHF-3, this overall rate of return is the result of combining a capital structure consisting of 55.34% debt and 44.66% equity with an average embedded cost of debt of 5.13% and a 12.00% return on equity.

VII. Allowance for Funds Used During Construction

Q70. What is the purpose of this section?

A70. This section develops AFUDC rates for Oliktok for 2023, 2024, and 2025.

Q71. How have you determined AFUDC rates for Oliktok?

A71. AFUDC is the "carrying cost" of capital invested in construction and deferred assets, which may be capitalized and added to an asset's cost or treated as a separate asset. Because AFUDC rates are generally intended to reflect a pipeline's cost of capital, they are usually based on the pipeline's own capital structure ratios, cost of debt, and authorized return on equity. However, determining an AFUDC rate for Oliktok is complicated because it is financed with capital contributions by its owner, which is capitalized as an E&P company, not a pipeline, and as a new pipeline, it has no previously authorized return on equity. Accordingly, consistent with Order 151, I calculated AFUDC rates for Oliktok based on data for a proxy group of oil and gas pipelines using the rate or return methodology described above.

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Q.72 What annual AFUDC rates do you recommend for Oliktok?

A.72 I prepared rate of return analyses for Oliktok following the Order 151 methodology in TL51-334 and TL52-334, which were filed January 6, 2023, and December 29, 2023, respectively. Because these analyses generally correspond to the data customarily used to develop AFUDC rates and the years at issue, I recommend the 8.54% and 8.53% overall rates from these analyses be used as AFUDC rates for 2023 and 2024, respectively. For 2025, when no analysis was prepared, I recommend that the 8.53% rate of return found in TL52-334 be carried forward. The specifics of each rate of return analysis are displayed on Schedule 17, Exhibit No. BHF-3.

VIII. <u>Conclusion</u>

Q73. Does that conclude your direct testimony in this case at this time?

A73. Yes, it does.

DATED this 1st day of July, 2026.

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Exhibit BHF-1

EXHIBIT BHF-1

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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration, University of Colorado at Boulder (Jan. 1977 to Dec. 1978)	Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.
Teaching Assistant, University of Texas at Austin (Jan. 1973 to Dec. 1976)	Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.
Internal Auditor, Sears, Roebuck and Company, Dallas, Texas (Nov. 1970 to Aug 1972)	Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.
Accounts Payable Clerk, Transcontinental Gas Pipeline Corp., Houston, Texas (May. 1969 to Aug. 1969)	Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics, University of Texas at Austin (Sep. 1974 to May 1980)	Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award. Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*
M.B.A., Finance and Accounting, University of Texas at Austin, (Sep. 1972 to Aug. 1974)	Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues. Professional Report: *Planning a Small Business Enterprise in Austin, Texas*
B.B.A., Accounting and Finance, Southern Methodist University, Dallas, Texas (Sep. 1967 to Dec. 1971)	Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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“Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

“Linear Algebra,” “Calculus,” “Sets and Functions,” and “Simulation Techniques,” contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

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“Capital Costs Within a Firm,” *Proceedings of the Southwestern Finance Association* (1977).

“The Cost of Capital to a Wholly-Owned Public Utility Subsidiary,” *Proceedings of the Southwestern Finance Association* (1977).

Selected Papers and Presentations

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"Perspectives on Texas Utility Regulation", TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).

"Legislative Changes Affecting Texas Utilities," Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).

"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

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"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

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"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

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"Effect of Inflation on Rate of Return," Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).

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"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

"Issues in Regulated Industries – Electric Utilities," University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).

"Investment Conditions and Strategies in Today's Markets," American Society of Women Accountants, Austin, Texas (January 1979).

"Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies," Financial Management Association, Minneapolis, Minnesota (October 1978).

"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"Public Utilities as Consumer Targets – Is the Pressure Justified?" University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

Exhibit BHF-2

EXHIBIT BHF-2

BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

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Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements

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Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements

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Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates

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Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity
85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return

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Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity
110.	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy – Energas	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG-280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return
162.	ETC Katy Pipeline, Ltd.	Texas RRC	9841	Dec-08	Revenue Requirements
163.	Oklahoma Natural Gas	Oklahoma CC	200800348	Jan-09	Rate of Return on Equity
164.	Entergy Mississippi, Inc.	Mississippi PSC	EC-123-0082	Mar 09	Rate of Return on Equity
165.	ENSTAR Natural Gas Company	Alaska RCA	U-09-69 U-09-70	Jun-09 Jul-09 Oct-09	Revenue Requirements, Cost Allocation, and Rate Design
166.	EasTrans, LLC	Texas RRC	9857	Jun-09	Rate of Return
167.	Oklahoma Natural Gas	Oklahoma CC	200900110	Jun-09	Rate of Return
168.	Crosstex CCNG Transmission Ltd.	Texas RRC	9858	Jun-09	Revenue Requirements
169.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul-09	Rate of Return
170.	ENSTAR Natural Gas Company	Alaska RCA	U-08-142	Jul-09	Gas Cost Adjustment
171.	Kinder Morgan Texas Pipeline, LLC	Texas RRC	9889	Jul-09	Rate of Return
172.	Koch Alaska Pipeline Company	Alaska RCA	TL 133-308	Aug-09	Rate of Return
173.	ExxonMobil Pipeline Co.	Alaska RCA	TL-147-304	Nov-09	Rate of Return
174.	Texas Gas Service Company	El Paso PURB	--	Dec-09	Rate of Return
175.	Unocal Pipeline Company	Alaska RCA	TL126-312	Dec-09	Rate of Return
176.	Kuparuk Transportation Company	Alaska RCA	P-08-05	Apr-10	Rate of Return
177.	Trans-Alaska Pipeline System	FERC	ISO9-348-000	Apr 10 Oct 10	Rate of Return
178.	Texas Gas Service	Texas RRC	9988	May 10 Aug 10	Rate of Return
179.	SEMCO Energy Gas Company	Michigan PSC	U-16169	Jun 10 Dec 10	Revenue Requirements
180.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul 10	Rate of Return
181.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-308	Aug 10	Rate of Return

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
182.	CPS Energy	Texas PUC	36633	Sep 10 Apr 11	Rate of Return for MOU
183.	ExxonMobil Pipeline Co.	Alaska RCA	TL-151-304	Dec 10	Rate of Return
184.	Unocal Pipeline Company	Alaska RCA	TL132-312	Feb 11	Rate of Return
185.	New Mexico Gas Company	NM PRC	11-00042-UT	Mar 11	Rate of Return
186.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-143-301	May 11	Rate of Return
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	ENSTAR Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	ENSTAR Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements
233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	TL46-334	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-___	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements
247.	SEMCO Energy Gas Co.	Michigan PSC	U-20479	May 19 Oct 19	Revenue Requirements
248.	Liberty Utilities (Fox River) LLC	AAA	01-18-0002-2510	Jul 19 Oct 19	Revenue Requirements
249.	AMP Intrastate Pipeline LLC	Texas RRC	10887	Aug 19	Revenue Requirements

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
250.	Corix Utilities (Texas) Inc.	Texas PUC	49923	Aug 19 Jul 20 Aug 20	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company	FERC	OR18-7-003	Nov 19 Feb 20 May 20 Jul 20	Rate of Return
252.	Texas Gas Service	Texas RRC	10928	Dec 19 Apr 20	Rate of Return
253.	Mississippi Power Company	Mississippi PSC	2019-UN-219	Feb 20	Rate of Return on Equity
254.	Corix Utilities (Texas)	Texas PUC	50557	Mar 20 Mar 21	Rate of Return and Excess ADFIT
255.	SouthCross CCNG Transmission	Texas RRC	10967	May 20	Revenue Requirements
256.	Kinder Morgan Border Pipeline LLC	Texas RRC	10980	Jun 20	Revenue Requirements
257.	Monarch Utilities I LP	Texas PUC	50944	Jul 20 Nov 20	Rate of Return
258.	West Texas Gas, Inc.	Texas RRC	10998	Aug 20	Revenue Requirements, Rate of Return, and Cost of Service Study
259.	Centric Gas Services, LLC	Texas RRC		Oct 20	Rate of Return
260.	CoServ Gas, Ltd	Texas RRC	00005136	Nov 20	Rate of Return
261.	Permian Highway Pipeline LLC	Texas RRC	00005306	Dec 20	Revenue Requirements
262.	Whistler Pipeline LLC	Texas RRC	00005675	Feb 21	Revenue Requirements
263.	Oklahoma Natural Gas	Oklahoma CC	202100063	May 21 Oct 21	Rate of Return
264.	Oliktok Pipeline Company	Alaska RCA	TL47-334	Jul 21	Rate of Return
265.	Participating Gas Utilities	Texas RRC	00007061	Jul 21 Oct 21	Excess Gas Cost Securitization
266.	Texas Pipeline Webb County Lean System, LLC	Texas RRC	00008188	Nov 21	Revenue Requirements
267.	Legend Gas Pipeline LLC	Texas RRC	00008714	Jan 22	Revenue Requirements
268.	Oliktok Pipeline Company	Alaska RCA	TL48-334	Mar 22	Rate of Return
269.	Texas Gas Service	Texas RRC	00009896	Jun 22 Oct 22	Rate of Return
270.	ENSTAR Natural Gas Company	Alaska RCA	U-22-081	Aug 22 Jul 23	Income Taxes, Cost Allocation, and Rate Design

EXHIBIT BHF-2

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
271.	Acacia Natural Gas, L.L.C.	Texas RRC	00010150	Aug 22	Revenue Requirements
272.	Corix Utilities (Texas)	Texas PUC	53815	Aug 22 Sep 23	Rate of Return, Cost Allocation, and Rate Design
273.	Oliktok Pipeline Company	Alaska RCA	TL51-334	Jan 23	Rate of Return
274.	Delaware-Permian Pipeline LLC	Texas RRC	00013058	Mar 23	Revenue Requirements
275.	SiEnergy LLC	Texas RRC	00013504	Mar 23	Rate of Return
276.	Texas Gas Service	Texas RRC	00014399	Jun 23	Rate of Return
277.	CoServ Gas, Ltd	Texas RRC	00014771	Jul 23	Rate of Return
278.	Matterhorn Express Pipeline, LLC	Texas RRC	00014719	Aug 23	Revenue Requirements
279.	TPL SouthTex Transmission Co. LP	Texas RRC	00015056	Aug 23	Revenue Requirements
280.	Oliktok Pipeline Company	Alaska RCA	TL52-334	Dec 23	Rate of Return
281. .	Kansas Gas Service	Kansas CC	24-KGSG-610-RTS	Mar 24 Jul 24	Rate of Return on Equity
282.	Delaware Link Ventures, LLC	Texas RRC	00016812	Mar 24	Revenue Requirements
283.	Texas Gas Service	Texas RRC	00017471	Jun 24 Sep 24	Rate of Return
284.	West Texas Gas, Inc.	Texas RRC	00017816	Jul 24	Revenue Requirements, Rate of Return, and Cost of Service Study
285.	Wind Energy Transmission Texas	Texas PUC	57299	Dec 24 Mar 25	Revenue Requirements
286.	Pecan Pipeline Company	Texas RRC	00020190	Mar 25	Revenue Requirements
287.	ENSTAR Natural Gas Company	Alaska RCA	U-25-019	May 25 Jan 26	Income Taxes, Cost Allocation, and Rate Design
288.	Texas Gas Service	Texas RRC	00028202	Jun 25 Oct 25	Rate of Return
289.	Southern Utilities Company	Texas PUC	58540	Aug 25 Mar 26 Mar 26	Rate of Return, Income Taxes
290.	Pikka Transportation Company	Alaska RCA	TL-789	Oct 25	Rate of Return
291.	San Jacinto Pipeline, LLC	Texas RRC	00029794	Dec 25	Revenue Requirements
292.	Hugh Brinson Pipeline, LLC	Texas RRC	00031664	May 26	Revenue Requirements

Exhibit BHF-3

OLIKTOK PIPELINE COMPANY

Exhibit No. BHF-3
Schedule 1
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OVERALL RATE OF RETURN

Capital	Percent of Total (a)	Cost		Weighted Cost
Debt	55.34%	5.13%	(b)	2.84%
Equity	44.66%	12.00%	(c)	5.36%
Total	100.00%			**8.20%**

(a) Schedule 3.
(b) Schedule 4.
(c) Schedule 5.

PROXY GROUP SELECTION

Company (a)	Ticker	Value Line Data (a) 2025 Debt Ratio	Estimated EPS Growth	Beta	Stock's Price Stability	I/B/E/S Growth Rate (b)	Comments (a)
Oil/Gas Distribution Industry							
Antero Midstream Corp.	AM	62%	13.5%	1.00	80	-	Excluded -- Primarily engaged in gathering and processing activities
Cheniere Energy, Inc.	LNG	74%	1.0%	0.90	65	-	Excluded -- Engaged in liquified natural gas
DT Midstream	DTM	35%	5.5%	0.95	85	10.3%	Included
Enbridge, Inc.	ENB	61%	4.5%	0.70	100	5.1%	Included
Kinder Morgan, Inc.	KMI	50%	6.5%	0.95	85	10.5%	Included
Kinetik Holdings Inc.	KNTK	127%	10.5%	1.10	55	2.5%	Excluded -- Anomalous capital structure
ONEOK, Inc.	OKE	58%	11.5%	1.25	65	6.1%	Included
Pembina Pipeline Corp.	PBA	42%	3.0%	0.70	100	-	Excluded -- Predominantly Canadian operations
South Bow Corp.	SOBO	68%	NMF	NMF	NMF	-	Excluded -- No meaningful data.
Targa Resources	TRGP	85%	18.5%	1.20	55	19.3%	Excluded -- Anomalous capital structure and earnings growth rates
TC Energy Corp.	TRP	68%	10.0%	0.85	90	3.5%	Included
Venture Global, Inc.	VG	80%	NMF	NMF	NMF	9.5%	Excluded -- Engaged in liquified natural gas
Williams Cos.	WMB	68%	9.0%	0.90	85	21.1%	Included
Pipeline MLPS Industry							
Cheniere Energy Partners, LP	CQP	97%	3.0%	0.90	60	-	Excluded -- Engaged in liquified natural gas
Energy Transfer, LP	ET	67%	7.0%	1.00	80	6.7%	Included
Enterprise Products Partners LP	EPD	53%	7.5%	0.85	100	8.8%	Included
Hess Midstream LP	HESM	87%	8.0%	0.95	80	-	Excluded -- 100% of revenues from Hess Corp.
MPLX LP	MPLX	64%	9.5%	0.90	95	3.6%	Included
Plains All American Pipeline LP	PAA	53%	14.0%	1.05	70	3.0%	Included
Plains GP Holdings, LP	PAGP	89%	13.0%	1.05	70	49.0%	Excluded -- Holding company for Plains All American Pipeline LP
Suburban Propane Partners LP	SPH	67%	6.0%	0.75	95	-	Excluded -- Primarily engaged in marketing and distributing propane and fuel oil
Western Midstream Partners, LP	WES	67%	8.5%	1.10	70	6.9%	Excluded -- Primarily engaged in gathering and processing activities

(a) *The Value Line Investment Survey* (May 22, 2026).
(b) LSEG Stock Reports Plus (May 29, 2026).

CAPITAL STRUCTURE

	March 31, 2026 (a)				December 31, 2025 (a)				December 31, 2024 (b)				December 31, 2023 (b)(c)			
	Debt		Equity		Debt		Equity		Debt		Equity		Debt		Equity	
Company	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total
DT Midstream	3,325	40.45%	4,895	59.55%	3,324	40.53%	4,878	59.47%	3,319	41.05%	4,766	58.95%	3,065	41.73%	4,280	58.27%
Enbridge, Inc.	108,037	61.46%	67,752	38.54%	103,994	61.47%	65,188	38.53%	101,143	59.48%	68,893	40.52%	80,799	55.62%	64,483	44.38%
Energy Transfer LP	69,336	58.23%	49,737	41.77%	68,333	58.23%	49,010	41.77%	59,760	56.50%	46,017	43.50%	52,388	54.39%	43,939	45.61%
Enterprise Products Partners LP	33,914	52.78%	30,347	47.22%	34,395	52.94%	30,570	47.06%	31,896	51.88%	29,589	48.12%	28,748	49.99%	28,759	50.01%
Kinder Morgan, Inc.	32,056	49.59%	32,583	50.41%	4,303	11.71%	32,449	88.29%	31,788	49.94%	31,867	50.06%	31,929	50.16%	31,729	49.84%
MPLX LP	25,634	64.20%	14,297	35.80%	25,653	63.84%	14,528	36.16%	20,948	60.27%	13,807	39.73%	20,431	61.69%	12,689	38.31%
ONEOK, Inc.	32,005	58.78%	22,447	41.22%	31,996	58.64%	22,569	41.36%	32,077	59.17%	22,133	40.83%	21,667	56.79%	16,484	43.21%
Plains All American Pipeline LP	10,956	46.08%	12,820	53.92%	10,696	44.99%	13,080	55.01%	7,211	35.51%	13,096	64.49%	7,305	34.72%	13,732	65.28%
TC Energy Corp.	45,738	55.18%	37,158	44.82%	58,886	61.48%	36,899	38.52%	58,979	60.59%	38,360	39.41%	63,201	61.84%	39,008	38.16%
Williams Cos.	30,302	66.65%	15,162	33.35%	28,661	65.65%	14,995	34.35%	26,456	64.06%	14,840	35.94%	25,713	63.33%	14,891	36.67%
Average		**55.34%**		**44.66%**		**51.95%**		**48.05%**		**53.85%**		**46.15%**		**53.02%**		**46.98%**

(a) 2026 Forms 10-Q and Quarterly Reports (March 31, 2026).
(b) 2024 Forms 10-K and Annual Reports.
(c) 2023 Forms 10-K and Annual Reports.

EMBEDDED COST OF DEBT

Company	**Cost of Debt (a)**
DT Midstream	4.59%
Enbridge, Inc.	4.85%
Energy Transfer LP	5.60%
Enterprise Products Partners LP	4.62%
Kinder Morgan, Inc.	5.37%
MPLX LP	4.97%
ONEOK, Inc.	5.49%
Plains All American Pipeline LP	4.98%
TC Energy Corp.	5.64%
Williams Cos.	5.18%
Average	**5.13%**

(a) Calculated from 2025 Form 10-Ks and Annual Reports and 2026 Forms 10-Q and Quarterly Reports (March 31, 2026).

OLIKTOK PIPELINE COMPANY

SUMMARY OF COST OF EQUITY ESTIMATES

	Cost of Equity Estimate
Discounted Cash Flow Model (a)	11.72%
Risk Premium Model (b)	10.95%
Capital Asset Pricing Model (c)	11.70%
Comparable Earnings Method (d)	13.61%
Average Cost of Equity Estimate	**12.00%**

(a) Schedule 6.
(b) Schedule 11.
(c) Schedule 15.
(d) Schedule 16.

SUMMARY OF DISCOUNTED CASH FLOW ESTIMATES

		Two-Stage Growth Rate	
	Single-Stage Growth (b)	General Form (c)	FERC Form (d)
Current Dividend Yield (a)	5.25%	5.25%	5.25%
Dividend Growth Factor	1.0371	1.0371	1.0263
Expected Dividend Yield	5.44%	5.44%	5.39%
Long-term Growth	7.42%	5.07%	5.25%
DCF Cost of Equity Estimates	**12.86%**	**10.52%**	**10.64%**

Average Two-Stage Growth DCF Cost of Equity Estimates	**10.58%**
Single-stage DCF Cost of Equity Estimate	**12.86%**
Average DCF Cost of Equity Estimate	**11.72%**

(a) Schedule 7.
(b) Schedule 8.
(c) Schedule 9.
(d) Schedule 10.

DIVIDEND YIELD (a)

Company	Spot May 2026	Last 3 Months	Last 6 Months	Last 12 Months	Average of Averages
DT Midstream	2.51%	2.50%	2.54%	2.80%	2.59%
Enbridge, Inc.	5.17%	5.19%	5.37%	5.56%	5.32%
Energy Transfer LP	7.05%	6.88%	7.17%	7.37%	7.12%
Enterprise Products Partners LP	5.98%	5.83%	6.17%	6.54%	6.13%
Kinder Morgan, Inc.	3.84%	3.63%	3.75%	3.99%	3.80%
MPLX LP	7.88%	7.70%	7.70%	7.63%	7.73%
ONEOK, Inc.	5.10%	4.82%	5.07%	5.28%	5.07%
Plains All American Pipeline LP	7.45%	7.40%	7.89%	8.28%	7.76%
TC Energy Corp.	3.78%	3.86%	4.03%	4.44%	4.03%
Williams Cos.	2.94%	2.86%	2.90%	3.05%	2.94%
Average	**5.17%**	**5.07%**	**5.26%**	**5.49%**	**5.25%**

(a) Calculated using price and dividend data from *Yahoo!* Finance.

SINGLE-STAGE DCF MODEL GROWTH

Company	Value Line Estimated EPS Growth (a)	I/B/E/S 5-Year Consensus Growth (b)	Average
DT Midstream	5.50%	10.30%	7.90%
Enbridge, Inc.	4.50%	5.10%	4.80%
Energy Transfer LP	7.00%	6.70%	6.85%
Enterprise Products Partners LP	7.50%	8.80%	8.15%
Kinder Morgan, Inc.	6.50%	10.50%	8.50%
MPLX LP	9.50%	3.60%	6.55%
ONEOK, Inc.	11.50%	6.10%	8.80%
Plains All American Pipeline LP	14.00%	3.00%	8.50%
TC Energy Corp.	10.00%	3.50%	6.75%
Williams Cos.	9.00%	21.10%	(c)
Average			**7.42%**

(a) *The Value Line Investment Survey* (May 22, 2026).
(b) LSEG Stock Reports Plus (May 29, 2026).
(c) Excluded because of anomalous I/B/E/S growth rate.

TWO-STAGE DCF MODEL GROWTH -- 20-YEAR GENERAL FORM

Year	DT Midstream Growth	DT Midstream Dividend	Enbridge, Inc. Growth	Enbridge, Inc. Dividend	Energy Transfer Growth	Energy Transfer Dividend	Enterprise Products Partners Growth	Enterprise Products Partners Dividend	Kinder Morgan Growth	Kinder Morgan Dividend	Average Growth Rate
2026		3.52		2.85		1.35		2.20		1.19	
2027	7.90%	3.80	4.80%	2.98	6.85%	1.44	8.15%	2.38	8.50%	1.29	
2028	7.90%	4.10	4.80%	3.13	6.85%	1.54	8.15%	2.57	8.50%	1.40	
2029	7.90%	4.42	4.80%	3.28	6.85%	1.65	8.15%	2.78	8.50%	1.52	
2030	7.90%	4.77	4.80%	3.44	6.85%	1.76	8.15%	3.01	8.50%	1.65	
2031	7.90%	5.15	4.80%	3.60	6.85%	1.88	8.15%	3.26	8.50%	1.79	
2032	3.88%	5.35	3.88%	3.74	3.88%	1.96	3.88%	3.38	3.88%	1.86	
2033	3.88%	5.56	3.88%	3.89	3.88%	2.03	3.88%	3.51	3.88%	1.93	
2034	3.88%	5.77	3.88%	4.04	3.88%	2.11	3.88%	3.65	3.88%	2.01	
2035	3.88%	6.00	3.88%	4.19	3.88%	2.19	3.88%	3.79	3.88%	2.09	
2036	3.88%	6.23	3.88%	4.36	3.88%	2.28	3.88%	3.94	3.88%	2.17	
2037	3.88%	6.47	3.88%	4.52	3.88%	2.37	3.88%	4.09	3.88%	2.25	
2038	3.88%	6.72	3.88%	4.70	3.88%	2.46	3.88%	4.25	3.88%	2.34	
2039	3.88%	6.98	3.88%	4.88	3.88%	2.55	3.88%	4.41	3.88%	2.43	
2040	3.88%	7.25	3.88%	5.07	3.88%	2.65	3.88%	4.59	3.88%	2.53	
2041	3.88%	7.53	3.88%	5.27	3.88%	2.76	3.88%	4.76	3.88%	2.62	
2042	3.88%	7.83	3.88%	5.47	3.88%	2.86	3.88%	4.95	3.88%	2.73	
2043	3.88%	8.13	3.88%	5.69	3.88%	2.97	3.88%	5.14	3.88%	2.83	
2044	3.88%	8.45	3.88%	5.91	3.88%	3.09	3.88%	5.34	3.88%	2.94	
2045	3.88%	8.77	3.88%	6.14	3.88%	3.21	3.88%	5.55	3.88%	3.05	
2046	3.88%	9.12	3.88%	6.37	3.88%	3.33	3.88%	5.76	3.88%	3.17	
20-Year Growth Rate		**4.87%**		**4.11%**		**4.62%**		**4.93%**		**5.02%**	

Year	MXLP Growth	MXLP Dividend	ONEOK Growth	ONEOK Dividend	Plains All-American Partners Growth	Plains All-American Partners Dividend	TC Energy Growth	TC Energy Dividend	Williams Companies Growth	Williams Companies Dividend	Average Growth Rate
2026		4.31		4.28		1.67		2.52		2.10	
2027	6.55%	4.59	8.80%	4.66	8.50%	1.81	6.75%	2.69	21.10%	2.54	
2028	6.55%	4.89	8.80%	5.07	8.50%	1.97	6.75%	2.87	21.10%	3.08	
2029	6.55%	5.21	8.80%	5.51	8.50%	2.14	6.75%	3.07	21.10%	3.73	
2030	6.55%	5.55	8.80%	6.00	8.50%	2.32	6.75%	3.27	21.10%	4.52	
2031	6.55%	5.92	8.80%	6.53	8.50%	2.51	6.75%	3.49	21.10%	5.47	
2032	3.88%	6.15	3.88%	6.78	3.88%	2.61	3.88%	3.63	3.88%	5.68	
2033	3.88%	6.38	3.88%	7.04	3.88%	2.71	3.88%	3.77	3.88%	5.90	
2034	3.88%	6.63	3.88%	7.31	3.88%	2.82	3.88%	3.92	3.88%	6.13	
2035	3.88%	6.89	3.88%	7.60	3.88%	2.93	3.88%	4.07	3.88%	6.37	
2036	3.88%	7.16	3.88%	7.89	3.88%	3.04	3.88%	4.23	3.88%	6.62	
2037	3.88%	7.44	3.88%	8.20	3.88%	3.16	3.88%	4.39	3.88%	6.87	
2038	3.88%	7.72	3.88%	8.52	3.88%	3.28	3.88%	4.56	3.88%	7.14	
2039	3.88%	8.02	3.88%	8.85	3.88%	3.41	3.88%	4.74	3.88%	7.42	
2040	3.88%	8.34	3.88%	9.19	3.88%	3.54	3.88%	4.92	3.88%	7.71	
2041	3.88%	8.66	3.88%	9.55	3.88%	3.68	3.88%	5.11	3.88%	8.00	
2042	3.88%	8.99	3.88%	9.92	3.88%	3.82	3.88%	5.31	3.88%	8.32	
2043	3.88%	9.34	3.88%	10.31	3.88%	3.97	3.88%	5.52	3.88%	8.64	
2044	3.88%	9.71	3.88%	10.71	3.88%	4.12	3.88%	5.73	3.88%	8.97	
2045	3.88%	10.08	3.88%	11.12	3.88%	4.29	3.88%	5.95	3.88%	9.32	
2046	3.88%	10.48	3.88%	11.55	3.88%	4.45	3.88%	6.19	3.88%	9.68	
		4.54%		**5.09%**		**5.02%**		**4.59%**		**7.94%**	**5.07%**

(a) 2026 Dividends from *Yahoo!* Finance.
(b) 2027-2031 growth rate from Schedule 8.
(c) 2032-2046 growth rate (long-term nominal GDP growth):

S&P Capital IQ (February 6, 2026).	3.92%
Energy Information Administration (*Annual Energy Outlook* -- April 15, 2025).	3.76%
Social Security Administration (*2025 OASDI Trustees Report*).	3.97%
Average	**3.88%**

TWO-STAGE DCF MODEL GROWTH -- FERC FORM

Company	I/B/E/S 5-Year Consensus Growth (a)	Long-term GDP Growth (b)	Weighted Average (c)
DT Midstream	10.30%	3.80%	8.13%
Enbridge, Inc.	5.10%	3.80%	4.67%
Energy Transfer LP	6.70%	1.90%	5.10%
Enterprise Products Partners LP	8.80%	1.90%	6.50%
Kinder Morgan, Inc.	10.50%	3.80%	8.27%
MPLX LP	3.60%	1.90%	3.03%
ONEOK, Inc.	6.10%	3.80%	5.33%
Plains All American Pipeline LP	3.00%	1.90%	2.63%
TC Energy Corp.	0.035	3.80%	3.60%
Williams Cos.	21.10%	3.80%	(d)
Average			**5.25%**

(a) LSEG Stock Reports Plus (May 29, 2026).

(b) Long-term nominal GDP growth for 2030 and beyond:

S&P Capital IQ (February 6, 2026).	3.89%
Energy Information Administration (Annual Energy Outlook -- April 15, 2025).	3.65%
Social Security Administration (2025 OASDI Trustees Report).	3.86%
Average	**3.80%**

(c) I/B/E/S Growth weighted 2/3 and GDP Growth weighted 1/3.

(d) Excluded because of anomalous I/B/E/S growth rate.

SUMMARY OF EQUITY RISK PREMIUM METHOD

Prospective Triple-B Public Utility Bond Yield (a)		6.06%
Equity Risk Premium:		
Beta-adjusted Total Market (b)	5.89%	
S&P Public Utilities (c)	3.91%	
Average Equity Risk Premium		4.90%
Equity Risk Premium Cost of Equity Estimate		**10.95%**

(a) Schedule 12.
(b) Schedule 13.
(c) Schedule 14.

OLIKTOK PIPELINE COMPANY

PROSPECTIVE TRIPLE-B UTILITY BOND YIELD

Prospective Yield on Triple-A Corporate Bonds (a):

2nd Quarter 2026	5.60%	
3rd Quarter 2026	5.50%	
4th Quarter 2026	5.50%	
1st Quarter 2027	5.50%	
2nd Quarter 2027	5.50%	
3rd Quarter 2027	5.50%	
Average		**5.52%**

Triple-B Public Utility vs. Triple-A Corporate (b):

	Moody's Yields (c)			
	Baa	**Aaa**	**Spread**	
June 2025	6.13%	5.47%		
July 2025	6.08%	5.45%		
August 2025	5.98%	5.35%		
September 2025	5.81%	5.21%		
October 2025	5.71%	5.13%		
November 2025	5.83%	5.26%		
December 2025	5.88%	5.31%		
January 2026	5.86%	5.34%		
February 2026	5.78%	5.30%		
March 2026	5.99%	5.48%		
April 2026	5.99%	5.42%		
May 2026	6.06%	5.56%		
Average -- Mar 2026 - May 2026	6.01%	5.49%	0.53%	
Average -- Dec 2025 - May 2026	5.93%	5.40%	0.53%	
Average -- Jun 2025 - May 2026	5.93%	5.36%	0.57%	
Average of Averages				**0.54%**

Prospective Triple-B Public Utility Bond Yield	**6.06%**

(a) *Blue Chip Financial Forecasts* (June 1, 2026).
(b) Moodys.com and Standardandpoors.com (June 9, 2026)

	Moody's	**S&P**
DT Midstream	Baa3	BBB-
Enbridge, Inc.	Baa2	BBB+
Energy Transfer LP	Baa2	BBB
Enterprise Products Partners LP	N/R	A-
Kinder Morgan, Inc.	Baa1	BBB+
MPLX LP	Baa2	BBB
ONEOK, Inc.	Baa2	BBB
Plains All American Pipeline LP	Baa2	BBB
TC Energy Corp.	Baa3	BBB+
Williams Cos.	Baa2	BBB+

(c) Moody's Investors Service.

BETA-ADJUSTED TOTAL MARKET EQUITY RISK PREMIUM

Historical Market Equity Risk Premium:			
Average return on S&P 500 (1926-2025) (a)	12.23%		
Average return on Long-term Corporate Bonds (1926-2025) (b)	5.96%		
Historical Market Equity Risk Premium		**6.27%**	
Forecasted Market Equity Risk Premium:			
Value Line Forecasted 3-5 Year Average Return (c)	11.77%		
Prospective Yield on Aaa Corporate Bonds (d)	5.52%		
Forecasted Market Equity Risk Premium		**6.26%**	
Average of Historical and Forecasted Market Equity Risk Premiums			**6.26%**
Proxy Group Beta (e)			**0.94**
Beta-adjusted Total Market Equity Risk Premium			**5.89%**

(a) *Kroll Cost of Capital Navigator.*
(b) Schedule 14, footnote (b), adjusted 4 bp to match average return on Long-term Corporte Bonds reported in Kroll LLC: *Summary Statistics of Annual Total Returns, Income Returns and Capital Appreciation Returns of Basic U.S. Asset Classes (1926-2022)* .
(c) *The Value Line Investment Survey* :

Date of Summary & Index	Estimated Median Price Appreciation Potential 3-5 Years	Annual Rate of Growth	Median of Estimated Div. Yields	Estimated Annual Total Return
June 27, 2025	45%	9.73%	2.20%	11.93%
July 25, 2025	40%	8.78%	2.10%	10.88%
August 29, 2025	40%	8.78%	2.20%	10.98%
September 26, 2025	40%	8.78%	2.10%	10.88%
October 31, 2025	40%	8.78%	2.10%	10.88%
November 28, 2025	45%	9.73%	2.30%	12.03%
December 26, 2025	40%	8.78%	2.10%	10.88%
January 30, 2026	35%	7.79%	2.10%	9.89%
February 27, 2026	40%	8.78%	2.00%	10.78%
March 27, 2026	50%	10.67%	2.10%	12.77%
April 24, 2026	45%	9.73%	2.00%	11.73%
May 29, 2026	50%	10.67%	2.10%	12.77%
June 12, 2026	45%	9.73%	2.10%	11.83%
Average -- Mar 2026 - May 2026				12.42%
Average -- Dec 2025 - May 2026				11.47%
Average -- Jun 2025 - May 2026				11.37%
Average of averages				**11.77%**

(d) Schedule 12.
(e) *The Value Line Investment Survey* (May 22, 2026).

	Beta
DT Midstream	0.95
Enbridge, Inc.	0.70
Energy Transfer LP	1.00
Enterprise Products Partners LP	0.85
Kinder Morgan, Inc.	0.95
MPLX LP	0.90
ONEOK, Inc.	1.25
Plains All American Pipeline LP	1.05
TC Energy Corp.	0.85
Williams Cos.	0.90
Average	**0.94**

S&P PUBLIC UTILITIES EQUITY RISK PREMIUM

Historical Market Equity Risk Premium:

Average return on S&P Public Utilities Index (1928-2025) (a)	10.79%	
Average return on Long-term Corporate Bonds (1928-2025) (b)	5.92%	
Unadjusted Historical Market Equity Risk Premium		**4.86%**
Adjustment for Public Utility Bonds:		
Average yield on Triple-A/Double-A Corporate Bonds (1928-2025) (a)	5.79%	
Average yield on Triple-B Public Utility Bonds (1928-2025) (a)	6.75%	
Adjustment for Public Utility Bonds		**-0.95%**
S&P Public Utilities Equity Risk Premium		**3.91%**

(a) 1928-2003 data from Workpapers to Exhibit FJH-9 of Testimony of Frank J. Hanly, Docket No. P-03-4. 2003 S&P data from Standard & Poor's *Analysts' Handbook* and 2004-2022 data from www.us.spindices.com and Ibbotson *SBBI Market Results for Stocks, Bonds, Bill, and Inflation* (data as of December 2014); and Mergent's *Public Utility Manual* and *Bond Record* and Moody's.com. 2023-2025 return on S&P Utilities Index from *Ycharts.com.*

(b) For 1928-2014 (a). Beginning in 2015 annual return on Long-term Corporate Bonds calculated from average yield in December on triple- and double-A rated corporate bonds.

	Annual Return		Average Yield			Annual Return		Average Yield	
Year	**S&P Utilities Index**	**Long-term Corporate Bonds**	**Triple-A/ Double-A Corporate**	**Triple-B Public Utility**	**Year**	**S&P Utilities Index**	**Long-term Corporate Bonds**	**Triple-A/ Double-A Corporate**	**Triple-B Public Utility**
1928	57.47%	2.84%	4.63%	5.33%	1977	8.64%	1.71%	8.13%	9.06%
1929	11.02%	3.27%	4.88%	5.76%	1978	-3.71%	-0.07%	8.83%	9.62%
1930	-21.96%	7.98%	4.66%	5.88%	1979	13.58%	-4.18%	9.79%	10.96%
1931	-35.90%	-1.85%	4.82%	6.90%	1980	15.08%	-2.62%	12.22%	13.95%
1932	-0.54%	10.82%	5.50%	8.78%	1981	11.74%	-0.96%	14.46%	16.60%
1933	-21.87%	10.38%	4.86%	9.38%	1982	26.52%	43.79%	14.10%	16.45%
1934	-20.41%	13.84%	4.22%	7.49%	1983	20.01%	4.70%	12.23%	14.20%
1935	76.63%	9.61%	3.78%	5.56%	1984	26.04%	16.39%	13.01%	14.53%
1936	20.69%	6.74%	3.35%	4.67%	1985	33.05%	30.90%	11.80%	12.96%
1937	-37.04%	2.75%	3.36%	5.09%	1986	28.53%	19.85%	9.25%	10.00%
1938	22.45%	6.13%	3.38%	5.26%	1987	-2.92%	-0.27%	9.53%	10.53%
1939	11.26%	3.97%	3.12%	4.50%	1988	18.27%	10.70%	9.83%	11.00%
1940	-17.15%	3.39%	2.93%	4.05%	1989	47.80%	16.23%	9.36%	9.97%
1941	-31.57%	2.73%	2.88%	3.84%	1990	-2.57%	6.78%	9.44%	10.06%
1942	15.39%	2.60%	2.91%	3.73%	1991	14.61%	19.89%	8.91%	9.55%
1943	46.07%	2.83%	2.80%	3.58%	1992	8.11%	9.39%	8.30%	8.86%
1944	18.03%	4.73%	2.77%	3.52%	1993	14.39%	13.19%	7.31%	7.91%
1945	53.33%	4.08%	2.67%	3.39%	1994	-7.94%	-5.76%	8.06%	8.63%
1946	1.26%	1.72%	2.58%	3.03%	1995	42.15%	27.20%	7.66%	8.29%
1947	-13.16%	-2.34%	2.66%	3.08%	1996	3.14%	1.40%	7.46%	8.17%
1948	4.01%	4.14%	2.86%	3.36%	1997	24.69%	12.95%	7.37%	7.95%
1949	31.39%	3.31%	2.71%	3.28%	1998	14.82%	10.76%	6.67%	7.26%
1950	3.25%	2.12%	2.66%	3.18%	1999	-8.85%	-7.45%	7.20%	7.88%
1951	18.63%	-2.69%	2.89%	3.39%	2000	59.70%	12.87%	7.72%	8.36%
1952	19.25%	3.52%	3.00%	3.53%	2001	-30.41%	10.65%	7.17%	8.03%
1953	7.85%	3.41%	3.26%	3.73%	2002	-29.92%	16.33%	6.71%	8.02%
1954	24.72%	5.39%	2.98%	3.51%	2003	26.38%	5.27%	5.91%	6.84%
1955	11.26%	0.48%	3.11%	3.43%	2004	24.02%	8.72%	5.77%	6.40%
1956	5.06%	-6.81%	3.41%	3.78%	2005	16.61%	5.87%	5.31%	5.93%
1957	6.36%	8.71%	3.96%	4.46%	2006	20.97%	3.24%	5.69%	6.32%
1958	40.70%	-2.22%	3.87%	4.43%	2007	19.32%	2.60%	5.73%	6.33%
1959	7.49%	-0.97%	4.45%	4.96%	2008	-29.10%	8.78%	5.86%	7.25%
1960	20.26%	9.07%	4.49%	4.97%	2009	11.86%	3.02%	5.53%	7.06%
1961	29.33%	4.82%	4.42%	4.83%	2010	5.67%	12.44%	5.07%	5.98%
1962	-2.44%	7.95%	4.40%	4.75%	2011	19.55%	17.95%	4.70%	5.57%
1963	12.36%	2.19%	4.33%	4.67%	2012	1.17%	10.68%	3.74%	4.86%
1964	15.91%	4.77%	4.45%	4.74%	2013	13.21%	-7.07%	4.27%	4.98%
1965	4.67%	-0.46%	4.53%	4.78%	2014	28.98%	17.28%	4.19%	4.80%
1966	-4.48%	0.20%	5.18%	5.60%	2015	-4.85%	0.87%	3.94%	5.03%
1967	-0.63%	-4.95%	5.59%	6.15%	2016	16.29%	3.73%	3.71%	4.68%
1968	10.32%	2.57%	6.28%	6.87%	2017	12.11%	11.58%	3.79%	4.38%
1969	-15.42%	-8.09%	7.12%	7.93%	2018	4.11%	-4.99%	4.01%	4.67%
1970	16.56%	18.37%	8.18%	9.18%	2019	26.35%	21.07%	3.47%	4.20%
1971	2.41%	11.01%	7.59%	8.63%	2020	0.48%	14.29%	2.56%	3.39%
1972	8.15%	7.26%	7.35%	8.17%	2021	17.67%	-3.08%	2.78%	3.35%
1973	-18.07%	1.14%	7.55%	8.17%	2022	1.57%	-21.52%	4.19%	5.03%
1974	-21.55%	-3.06%	8.71%	9.84%	2023	-7.08%	0.56%	4.99%	5.84%
1975	44.49%	14.64%	9.00%	10.96%	2024	23.43%	0.22%	5.16%	5.76%
1976	31.81%	18.65%	8.59%	9.82%	2025	16.04%	3.90%	5.21%	5.79%
Average						**10.79%**	**5.92%**	**5.79%**	**6.75%**

EMPIRICAL CAPITAL ASSET PRICING MODEL

Prospective Yield on Long-term Treasury Bonds (a):			
2nd Quarter 2026	5.00%		
3rd Quarter 2026	5.00%		
4th Quarter 2026	4.90%		
1st Quarter 2027	4.90%		
2nd Quarter 2027	4.80%		
3rd Quarter 2027	4.80%		
Average			**4.90%**
Unadjusted Risk Premium Component:			
Market Equity Risk Premium (b)	7.12%		
Unadjusted Component Weighting	25.0%		
Unadjusted Risk Premium Component		**1.78%**	
Beta Adjusted Risk Premium Component:			
Market Equity Risk Premium (b)	7.12%		
Proxy Group Beta (e)	0.94		
Adjusted Component Weighting	75.0%		
Unadjusted Risk Premium Component		**5.02%**	
Empirical Equity Risk Premium			**6.80%**
Empirical CAPM Cost of Equity Estimate			**11.70%**

(a) *Blue Chip Financial Forecasts* (June 1, 2026).

(b) Market Equity Risk Premium:

Historical Market Equity Risk Premium:		
Average return on S&P 500 (1926-2025) (c)	12.23%	
Average Income Return on LT Government Bonds (1926-2025) (c)	4.86%	
Historical Market Equity Risk Premium		7.37%
Forecasted Market Equity Risk Premium:		
Value Line Forecasted Average Return (3-5 Years) (d)	11.77%	
Prospective Yield on Long-term Treasury Bonds (a)	4.90%	
Forecasted Market Equity Risk Premium		6.87%
Average of Historical and Forecasted Market Equity Risk Premiums		**7.12%**

(c) Kroll Cost of Capital Navigator.

(d) Schedule 13, footnote (b).

(e) Schedule 13, footnote (d).

COMPARABLE EARNINGS METHOD

Company (a)	Ticker	Domicile	Price Stability Index (a)	Projected 2029-2031 (b) Earnings per Share	Net Book Value	Return on Equity
Sun Communities Inc.	SUI	US	85	2.40	60.00	4.00%
Welltower Inc.	WELL	US	85	4.40	75.55	5.82%
Casella Waste Sys.	CWST	US	85	2.00	28.90	6.92%
Assurant Inc.	AIZ	US	85	25.00	249.65	10.01%
Prestige Consumer	PBH	US	85	6.75	66.65	10.13%
Tyson Foods 'A'	TSN	US	85	6.75	65.40	10.32%
Ingles Markets	IMKTA	US	85	12.35	118.40	10.43%
Corteva, Inc.	CTVA	US	85	5.50	51.90	10.60%
Weyerhaeuser Co.	WY	US	85	1.40	12.90	10.85%
RPM Int'l	RPM	US	85	6.65	61.25	10.86%
Martin Marietta	MLM	US	85	30.00	267.50	11.21%
Tootsie Roll	TR	US	85	1.95	16.65	11.71%
Kimco Realty	KIM	US	85	2.05	16.65	12.31%
MGIC Investment	MTG	US	85	4.70	37.50	12.53%
Copart, Inc.	CPRT	US	85	2.10	16.45	12.77%
Dolby Labs.	DLB	US	85	5.25	40.35	13.01%
Nasdaq, Inc.	NDAQ	US	85	5.30	40.25	13.17%
Casey's Gen'l Stores	CASY	US	85	25.50	189.10	13.48%
Equinix, Inc.	EQIX	US	85	22.50	165.34	13.61%
Allstate Corp.	ALL	US	85	28.00	195.60	14.31%
Universal Corp.	UVV	US	85	9.60	66.65	14.40%
PriceSmart	PSMT	US	85	7.25	50.00	14.50%
Brady Corp.	BRC	US	85	6.50	44.25	14.69%
McCormick & Co.	MKC	US	85	4.20	28.25	14.87%
AT&T Inc.	T	US	85	3.30	21.5	15.35%
PACCAR Inc.	PCAR	US	85	8.25	52.65	15.67%
L3Harris Technologies	LHX	US	85	20.00	127.10	15.74%
Brown & Brown	BRO	US	85	6.25	39.70	15.74%
Chevron Corp.	CVX	US	85	15.00	90.90	16.50%
JPMorgan Chase	JPM	US	85	30.50	179.15	17.02%
Kenvue Inc.	KVUE	US	85	1.35	7.85	17.20%
Franklin Electric	FELE	US	85	6.00	34.50	17.39%
MSA Safety	MSA	US	85	11.25	63.15	17.81%
Pfizer, Inc.	PFE	US	85	2.80	15.60	17.95%
S&P Global	SPGI	US	85	24.30	126.00	19.29%
RTX Corp.	RTX	US	85	12.00	61.75	19.43%
Nordson Corp.	NDSN	US	85	15.50	79.75	19.44%
Median						**13.61%**

(a) *The Value Line Investment Survey* (May 22, 2026).

DT Midstream	85
Enbridge, Inc.	100
Energy Transfer LP	80
Enterprise Products Partners LP	100
Kinder Morgan, Inc.	85
MPLX LP	95
ONEOK, Inc.	65
Plains All American Pipeline LP	70
TC Energy Corp.	90
Williams Cos.	85
Average	**86**

(b) Retrieved from *The Value Line Investment Survey* (June 8, 2026).

OLIKTOK PIPELINE COMPANY

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Year	Debt	Equity	Cost of Debt (b)	Return on Equity (a)	AFUDC Rate
2024 (a)	57.94%	42.06%	4.86%	13.61%	8.54%
2025 (b)	56.18%	43.82%	5.02%	13.03%	8.53%
2026 (b)	56.18%	43.82%	5.02%	13.03%	8.53%

(a) Exhibit No. BHF-4, Schedule 1 in TL51-334.
(b) Exhibit No. BHF-4, Schedule 1 in TL52-334.

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: John M. Espindola, Chair; Steve DeVries; Mark Johnston; John C. Springsteen; Julie C. Vogler

In the Matter of Revenue Requirement Study Designated as TL57-334 filed by OLIKTOK PIPELINE COMPANY for Natural Gas Transportation Service)	TL57-334

PREPARED DIRECT TESTIMONY OF ERIK G. WETMORE ON BEHALF OF OLIKTOK PIPELINE COMPANY

Introduction

Q1. Please state your name, business address, and occupation.

A1. My name is Erik G. Wetmore. My business address is 551 Mikado Place, Danville, California 94526. I am a Principal in the consulting firm Turner Wetmore Collins, LLC, a firm that provides consulting services to the regulated sector of the energy transportation industry.

Q2. Please describe your professional and educational background.

A2. I have more than 35 years of professional experience, primarily in advising regulated energy pipeline companies on ratemaking and regulatory accounting issues. My experience includes providing testimony in rate proceedings before the Regulatory Commission of Alaska ("Commission" or "RCA") and various other courts and regulatory commissions. I received an M.B.A., with concentrations in Finance and Economics, from the University of Chicago Booth School of Business, and a B.A. in Mathematics and Economics from the University of California at Santa Barbara. I also earned a Certified

LAW OFFICES OF
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A PROFESSIONAL CORPORATION
255 E. FIREWEED LANE, SUITE 200
ANCHORAGE, ALASKA 99503-2025
(907) 277-1604

Public Accountant license. Additional details about my professional and educational background are provided as Exhibit EGW-1.

Q3. What is the purpose of your direct testimony in this proceeding?

A3. I describe the information being submitted in support of the pipeline transportation rate filing of Oliktok Pipeline Company ("Oliktok") for natural gas transportation service, and I explain the ratemaking computations that support Oliktok's proposed pipeline transportation rate filing.

Q4. Please describe how your testimony is organized.

A4. First, I present Oliktok's existing and proposed rates. Second, I explain the methodology used to calculate Oliktok's normalized test-year revenue requirement. Third, I describe the supporting information provided by Oliktok in its rate filing as required by Section 275(a). Fourth, I discuss my computation of the revenue requirement for the normalized test-year and the resulting proposed rates. Fifth, I describe the pro forma ratemaking adjustments that I make to operating expenses for the normalized test-year. Sixth, I describe the pro forma ratemaking adjustments that I make to rate base for the normalized test-year. Seventh, I describe the pro forma ratemaking adjustments that I make to throughput for the normalized test-year.

Q5. What witnesses have you relied upon in preparing your testimony?

A5. Mr. Raj D. Choudhury provided me with information regarding Oliktok's operating expenses, rate base, and throughput that I need to calculate a revenue requirement for the normalized test-year and the corresponding tariff rates. Dr. Bruce H. Fairchild provided me with the cost of capital elements (capital structure, cost of debt, and rate of return on equity) that I need to calculate a revenue requirement for the normalized test-year.

I. <u>Summary of Oliktok's Existing and Proposed Rates</u>

Q6. What is the basis for Oliktok's existing intrastate tariff rates?

A6. On December 1, 2025, Oliktok filed Tariff Advice Letter No. TL56-334, which reflected its annual revision to its rates for the intrastate transportation of natural gas, as required under the Oliktok Settlement Agreement accepted by the Commission in Order No. P-24-007(2) (May 16, 2024). On December 18, 2025, the Commission approved Tariff Sheet No. 37 in Letter Order No. L2500352. These rates became effective on January 1, 2026.

Q7. Please summarize Oliktok's most recently approved permanent tariff rates and its proposed intrastate tariff rates.

A7. Oliktok's most recently approved permanent and proposed per Mcf tariff rates for deliveries to the Gas Hydrates Project ("GHP"), Gas Spur Pipeline ("GSP"), and the Kuparuk River Unit ("KRU") are as follows:

Destination	Most Recently Approved Permanent	Proposed
GHP	$0.346	$0.914
GSP	$0.555	$1.464
KRU	$0.580	$1.528

Q8. By how much would Oliktok under-recover its revenue requirement if its rates were set at their most recently approved levels?

A8. As shown on Exhibit EGW-2, Schedule 4, and Exhibit EGW-3, Page 1, I determine that Oliktok would under-recover its revenue requirement by 164% for the normalized test-year

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if its rates were to remain at their existing levels. In dollar terms, Oliktok's annual under-recovery would be approximately $7.4 million.

II. Revenue Requirement Methodology

Q9. What methodology did you use to calculate Oliktok's revenue requirement for the normalized test-year?

A9. I used a traditional depreciated original cost ("DOC") methodology to calculate Oliktok's revenue requirement. Under this methodology, a pipeline is allowed to recover in its revenue requirement its operating expenses and a reasonable return of and on capital.

Q10. What is return *of* capital?

A10. Return of capital is the recovery of invested capital in the regulated asset over its life through periodic charges to depreciation (of carrier property).

Q11. What is return *on* capital?

A11. In general, return on capital (which is also commonly referred to as return on rate base) is an allowance for interest incurred on long-term debt and a return on equity to compensate investors for the risk of their investment. Return on rate base is calculated by multiplying the pipeline's rate base by its weighted cost of capital. Dr. Fairchild's testimony describes the development of Oliktok's weighted cost of capital. Since the return on rate base is an after-tax return, the revenue requirement includes an income tax allowance. The income tax allowance grosses up the after-tax return on rate base to compensate investors for their tax liability.

Q12. Please describe how a DOC rate base is computed for a pipeline company.

A12. A DOC rate base is computed as follows:

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+ Carrier Property in Service

+ Allowance for Funds Used During Construction (“AFUDC”)

- Accumulated Depreciation

- Accumulated Amortization of AFUDC

+ Working Capital

<u>- Accumulated Deferred Income Taxes (“ADIT”)</u>

= DOC Rate Base

Q13. What is carrier property in service and accumulated depreciation?

A13. Carrier property in service is the cumulative amount invested in regulated assets, adjusted for retirements. Carrier property in service does not include construction work in progress (“CWIP”). Depreciation of carrier property systematically allocates the value of depreciable property over the economic life of the property. Depreciation expense is included in the revenue requirement, providing the pipeline with a systematic return of capital.

Q14. What is AFUDC?

A14. AFUDC compensates investors for funds expended to construct pipeline assets before the assets are placed in service. AFUDC is transferred to rate base at the same time the associated CWIP balance is transferred to carrier property in service. AFUDC is amortized, and the amortization of AFUDC is included in the revenue requirement. The unamortized balance of AFUDC is included in rate base. Although AFUDC is not recorded in Oliktok’s accounting records, it is included in ratemaking calculations, consistent with common pipeline ratemaking practice.

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Q15. What is working capital?

A15. Working capital consists of investments and prepayments required to support the operation of a pipeline. For the purposes of Oliktok's revenue requirement calculation, working capital is comprised of materials & supplies and prepayments.

Q16. What are accumulated deferred income taxes ("ADIT")?

A16. ADIT results from tax timing differences, typically due to the difference in timing of straight-line depreciation for ratemaking purposes and accelerated depreciation for tax purposes. Accelerated tax depreciation results in larger deductions for depreciation, and correspondingly, the incurrence of lower income tax liabilities, in the earlier years of an asset's life, and smaller deductions and correspondingly higher income tax liabilities in the later years of an asset's life. The tax liability timing differences are accumulated, and the ADIT balance is deducted from rate base.

III. Information Submitted in Support of 275(a) Rate Filing

Q17. Please describe the Section 275(a) information submitted in support of Oliktok's rate filing.

A17. In accordance with Section 275(a) of the Commission's regulations, Oliktok is submitting the following information in support of its rate filing, which is attached as Exhibit EGW-2: (1) **"A comparative statement of assets, liabilities, and other credits as of the end of each of the two calendar or fiscal years preceding the date of filing."** Oliktok's Comparative Balance Sheet (included on page 110 of its 2025 RCA Annual Report) is Schedule 1 to Exhibit EGW-2.[1]

[1] The RCA Annual Report includes data for both the current and the prior calendar year.

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(2) **"A comparative statement of income and operating expenses as of the end of each of the two calendar or fiscal years preceding the date of filing."** Oliktok's Income Statement (included on page 114 of its 2025 RCA Annual Report) is Schedule 2 to Exhibit EGW-2.

(3) **"A comparative statement of changes in the utility's or pipeline carrier's equity position to include fluctuations in capital stock, retained earnings, owner's equity, or fund balances for each of the two calendar or fiscal years preceding the date of filing."** Oliktok's Unappropriated Retained Income Statement (included on page 119 of its 2025 RCA Annual Report) is Schedule 3 to Exhibit EGW-2.

(4) **"A schedule showing the amount of the proposed rate change, both in absolute dollars and as a percentage increase or decrease, applied to the most recent approved permanent tariff rates and charges for each customer or service classification."** In Schedule 4 of Exhibit EGW-2, lines 1 through 3, I present the proposed intrastate rates for deliveries to GHP, GSP, and KRU. On lines 4 through 12, I present the most recent approved permanent tariff rates for each intrastate destination, and the proposed rate change, in absolute dollars and as a percentage increase, for each intrastate destination relative to Oliktok's most recent approved permanent tariff rates.

(5) **"A schedule showing the computations of revenue requirement, and revenue deficiency or surplus, in both absolute dollars and as a percentage of revenues, for the normalized test-year."** In Schedule 5 of Exhibit EGW-2, I compute Oliktok's total revenue requirement and present Oliktok's projected revenue deficit, in both absolute dollars and as a percentage of revenues, for the normalized test-year.

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(6) **"A schedule showing test-year operating revenues and expenses, pro forma adjustments, and the resulting normalized test-year operating revenues and expenses."** Schedule 6 of Exhibit EGW-2 presents test-year operating revenues and expenses, pro forma adjustments, and the resulting normalized test-year operating revenues and expenses for Oliktok.

(7) **"A schedule showing the computation of and a narrative explanation for any pro forma adjustments to the test-year results of operations."** Schedule 7 of Exhibit EGW-2 presents the computation of, and a narrative explanation for, all pro forma adjustments to the test-year results of operations.

(8) **"A schedule showing the computation of the pro forma provision for income taxes for the normalized test-year."** In Schedule 8 of Exhibit EGW-2, I compute an income tax allowance for the normalized test-year.

(9) **"A schedule showing the computation of rate base using a 13-month average (the arithmetic sum of the beginning of each month net balance for the 12-month test period, plus the balance at the end of the twelfth month of the test period, divided by 13) of all rate-base components except cash working capital allowance, and using any other rate-base theory the utility or pipeline carrier considers appropriate and supportable."** In Schedule 9.1 of Exhibit EGW-2, I compute a 13-month average rate base, including pro forma adjustments. Additional discussion regarding this computation is included later in this testimony.

(10) **"A summary of utility, or pipeline, plant and depreciation for each of the two calendar or fiscal years preceding the date of filing, showing plant in service;**

depreciation expense for each plant account; depreciation method; asset life; and net salvage used for computing that depreciation expense and the end-of-year balance of each plant account and the related account for accumulated depreciation.” Schedule 10 of Exhibit EGW-2 includes a summary of plant and depreciation from 2023 through 2025.

(11) **“A schedule showing the pro forma cash working capital requirement based on the normalized test-year.”** Oliktok is not seeking to recover cash working capital requirements in its proposed rates.

(12) **“A schedule showing the computation of weighted cost of capital, separately delineating the percentage amount and embedded cost of debt, and the percentage amount and rate of return on equity, together with a schedule showing the resultant returns on each of the rate bases computed in (9) of this subsection.”** Schedule 12 of Exhibit EGW-2 shows the weighted cost of capital and resultant return on rate base computed in Schedule 9.1 of Exhibit EGW-2. The weighted cost of capital was computed by Dr. Fairchild. While it is not used in Oliktok’s rate calculations, Oliktok’s embedded cost of debt and capital structure are also included at Schedule 13 and Schedule 1 of Exhibit EGW-2. *See* Oliktok’s 2025 RCA Annual Report at pages 226-27 (Oliktok’s Long-Term Debt Statement) and at page 110 (Oliktok’s Comparative Balance Sheet).

(13) **“A schedule showing all liabilities of long-term debt for each of the two calendar or fiscal years preceding the filing, including a description of each obligation; nominal date of issue; date of maturity; authorized face amount; and the computation of the embedded cost of debt used in (12) of this subsection.”** The embedded cost of debt used

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in Oliktok's rate calculations is shown in Schedule 4 to Exhibit BHF-3 supporting Dr. Fairchild's testimony. While it is not used in its rate calculations, a schedule showing Oliktok's long-term debt is also included at Schedule 13 of Exhibit EGW-2.

(14) **"As provided for under 3 AAC 48.153, prefiled direct testimony in support of the information filed under this subsection, together with a list of the witnesses filing testimony."** Oliktok is sponsoring the testimony of:

- Raj D. Choudhury
- Dr. Bruce H. Fairchild
- Erik G. Wetmore

(15) **"For a pipeline carrier seeking to collect in rates money to cover costs to dismantle or remove a pipeline facility or restore a right-of-way…"** Oliktok is not seeking to collect in its proposed rates money to cover costs to dismantle or remove a pipeline facility or restore a right-of-way.

(16) **"For a pipeline carrier that has performed dismantlement or removal of a pipeline facility or the restoration of a right-of-way during the test-year, a schedule showing any adjustments pertaining to the costs of the dismantlement or removal of the pipeline facility or the restoration of the right-of-way included in the schedule submitted in accordance with (5) of this subsection."** Oliktok is not seeking to collect in its proposed rates money to cover costs to dismantle or remove a pipeline facility or to restore a right-of-way. Thus, no dismantlement costs are included in the schedule submitted in accordance with (5) of this subsection.

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IV. Computation of Revenue Requirement and Proposed Rates

Q18. What historical test-year do you use to evaluate the revenue requirement?

A18. The historical test-year is based on 2025 actual data. Through a series of pro forma ratemaking adjustments, the "historical test-year [is] adjusted to reflect the effect of known and measurable changes and to delete or average the effect of unusual and nonrecurring events, for the purpose of determining a test-year which is representative of normal operations in the immediate future." See 3 AAC 48.820(42).

Q19. What is the total revenue requirement that you compute for the normalized test-year?

A19. The total revenue requirement that I compute for the normalized test-year is shown in Table 1 below, as well as Schedule 5, Exhibit EGW-2 of Oliktok's rate filing.

Table 1: Total Revenue Requirement ($000's)

Line No.	Description	Normalized Test-Year[2]
1	Operating Expenses	$6,445
2	Depreciation Expense	$2,169
3	Amortization of AFUDC	$123
4	Return on Rate Base	$2,573
5	Income Tax Allowance	$658
6	Total Revenue Requirement	$11,968

Q20. Please describe how you compute operating expenses for the normalized test-year, as reflected on line 1 of Table 1.

A20. A schedule showing historical test-year operating expenses and normalized test-year operating expenses is presented in Schedule 6, Page 1, of Exhibit EGW-2. The 2025

[2] The amounts in the table above are rounded to the nearest thousand dollars.

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historical test-year operating expense data comes from Oliktok's books and records. It reflects the information that was reported in Oliktok's 2025 Annual Report filed with this Commission. This schedule shows historical test-year operating expenses, pro forma adjustments, and the resulting normalized test-year operating expenses. The normalized test-year operating expenses are based on historical test-year operating expenses adjusted to reflect the effect of known and measurable changes and to delete or average the effect of unusual and nonrecurring events. I discuss a pro forma adjustment to operating expenses later in my testimony related to rate case expense.

Q21. Please describe how you compute depreciation expense for the normalized test-year, as reflected on line 2 of Table 1.

A21. My computation of depreciation expense is presented on Schedule 10 of Exhibit EGW-2. For the normalized test-year, I apply a composite depreciation factor based on a December 31, 2040, depreciable end-life to net depreciable carrier property in service for the normalized test-year to calculate the amount of depreciation expense that is included in the revenue requirement. This is consistent with the depreciable end-life stipulated to in Oliktok's February 1, 2024, Settlement Agreement that was accepted by the Commission on May 16, 2024 ("2024 Settlement Agreement").[3] I discuss a pro forma adjustment to depreciation expense later in my testimony related to an annualization adjustment to property placed in service in September 2025.

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[3] See Order P-24-007(2), *Order Granting Petition, Accepting Settlement Agreement, Approving Tariff Sheet, and Closing Docket*, dated May 16, 2024.

Q22. Please describe how you compute amortization of AFUDC for the normalized test-year, as reflected on line 3 of Table 1.

A22. I amortize AFUDC using the same composite depreciation factors used to depreciate carrier property. This computation is set forth on Workpaper 1.2 of Exhibit EGW-2. I discuss a pro forma adjustment to AFUDC amortization expense later in my testimony related to an annualization adjustment to property placed in service in September 2025.

Q23. Please describe how you compute return on rate base for the normalized test-year, as reflected on line 4 of Table 1.

A23. My computation of the return on rate base is set forth on Schedule 12 of Exhibit EGW-2. As discussed earlier in my testimony, the weighted cost of capital that I apply to rate base is sponsored by Dr. Fairchild, and its computation is discussed in his testimony. My computation of the rate base is set forth on Schedules 9 and 9.1 of Exhibit EGW-2. As shown on Schedule 9, I start with the stipulated year-end 2022 rate base components per Oliktok's 2024 Settlement Agreement. I then update rate base for the following activity from 2023 and forward: changes to carrier property in service due to additions, retirements, and other adjustments; changes to accumulated depreciation due to depreciation expense, retirements, and other adjustments; and additions to and amortization of AFUDC. I also update the DOC rate base to reflect the appropriate amounts of working capital and ADIT.

Q24. Please describe how you compute ADIT.

A24. I start with the stipulated year-end 2022 state and federal ADIT balances set forth in Oliktok's 2024 Settlement Agreement. I then update ADIT from 2023 through the 2025 historical test-year to account for differences in timing of depreciation for ratemaking and

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tax purposes, assuming accelerated methods of tax depreciation and the maximum statutory federal and state income tax rates.

Q25. Please describe how you compute income tax allowance for the normalized test-year, as reflected on line 5 of Table 1.

A25. My computation of the income tax allowance for the normalized test-year is presented in Schedule 8 of Exhibit EGW-2. To calculate the income tax allowance, I identify the equity portion of the total after-tax return on rate base. I adjust the equity portion of the return on rate base to account for permanent federal and state income tax differences. I calculate the net-to-tax multiplier assuming the maximum statutory federal and state income tax rates. I assume a 21 percent federal income tax rate and a 9.4 percent state income tax rate for my calculation.

Q26. Please explain how you compute the tariff rates proposed in Oliktok's rate filing.

A26. My computation of Oliktok's proposed intrastate tariff rates is set forth on Schedules 4 and 5 of Exhibit EGW-2. As shown on Schedule 5, I apply a rolled-in barrel-mile rate design methodology to compute Oliktok's proposed intrastate rates for deliveries to GHP, GSP, and KRU. That rate design methodology allocates the total revenue requirement to destinations based upon whether or not revenue requirement components are distance-related. Total distance-related revenue requirement components are apportioned according to a destination's Mcf-mile share of total Mcf-mile deliveries. Total non-distance-related revenue requirement components are apportioned on a per-Mcf basis.

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V. Pro Forma Adjustments to Historical Test-Year Operating Expenses

Q27. What pro forma adjustment do you make to historical test-year operating expenses?

A27. I make one forma adjustment for rate case expense, amortizing projected rate case expense over three years. Oliktok's historical test-year operating expenses do not include any amounts associated with a rate case.

VI. Pro Forma Adjustments to Historical Test-Year Rate Base

Q28. Earlier in your testimony, you stated that you make pro forma ratemaking adjustments to the historical test-year rate base. Please explain why such pro forma adjustments to the historical test-year rate base are appropriate.

A28. Pro forma adjustments to a historical test-year are appropriate when they are needed to develop a normalized test-year which is representative of normal operations when the rates will be in effect. Oliktok placed $13.0 million of property in service in September of 2025. Because this proceeding is intended to establish rates that will not become effective until the second half of 2026, this actual historic property addition will be used in providing service throughout the entire period during which the proposed rates will be in effect.

Absent this pro forma adjustment, Oliktok's forward-looking rates would reflect only 4/13ths of the investment because the September 2025 addition is included in the 13-month average rate base calculation for only four months of the unadjusted 13-month average rate base calculation. As a result, the normalized test-year rate base would understate the investment that will be in service when the proposed rates become effective and would not accurately reflect all of the costs associated with providing service.

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Q29. Please describe how you directly adjust the historical test-year rate base for the September 2025 property addition.

A29. As shown on Schedule 9.1 of Exhibit EGW-2, line 12, I reflect the September 2025 property addition in all months of the 13-month average rate base calculation. This adjustment annualizes the investment by recognizing the property addition for the entire test year rather than only the four months following its September 2025 in-service date. As a result, the normalized test-year rate base reflects the full amount of the investment that will be in service when the proposed rates become effective.

Q30. Did you make any other pro forma adjustments to the historical test-year rate base to synchronize the revenue requirement for the property placed in service in September 2025?

A30. Yes. As shown on Schedule 9.1 of Exhibit EGW-2, in addition to the direct pro forma adjustment I described above, I make two additional pro forma adjustments to synchronize the revenue requirement associated with the September 2025 property addition.

First, on line 13, I increase accumulated depreciation, which correspondingly reduces rate base, to reflect the incremental depreciation that would have been recorded if the September 2025 property addition had been in service for all of 2025. This pro forma adjustment also synchronizes rate base with the depreciation expense reflected in the normalized test-year revenue requirement.

Second, on line 14, I decrease net AFUDC, which correspondingly reduces rate base, to reflect the incremental AFUDC amortization that would have been recorded if the September 2025 property addition had been in service for all of 2025. This adjustment

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also synchronizes rate base with the AFUDC amortization expense reflected in the normalized test-year revenue requirement.

VII. Pro Forma Adjustments to Historical Test-Year Throughput

Q31. Earlier in your testimony, you stated that you make a pro forma ratemaking adjustment to throughput for the historical test-year. Please explain why such a pro forma adjustment to the historical test-year throughput is appropriate.

A31. Oliktok's historical test-year throughput substantially exceeds both the actual throughput experienced during 2026 to date and the throughput projected for the remainder of 2026. Because this proceeding is intended to establish rates that will not become effective until the second half of 2026, the historical 2025 test-year throughput is not representative of the throughput expected to be transported while the proposed rates are in effect. Accordingly, I made a pro forma adjustment to reflect the throughput that is expected to occur during the period the proposed rates will apply, thereby ensuring that the rate design is based on representative operating conditions.

Q32. Please describe the pro forma adjustment you make to historical test-year throughput.

A32. As shown on Schedule 7, Page 5, of Exhibit EGW-2, I adjust historical 2025 test-year throughput to reflect an annualized level of throughput based on actual 2026 volumes through June 12, 2026, together with projected throughput for the remainder of 2026. The actual throughput was provided to me by Mr. Choudhury, and the projected throughput was based on forecasts provided by Oliktok's shippers.[4]

[4] All of the throughput is expected to be delivered to GSP and KRU. However, Oliktok expects to resume deliveries to GHP in the future, and for rate design purposes, I therefore assumed 1 Mcf will be delivered to GHP.

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Q33. Does this conclude your direct testimony?

A33. Yes, it does.

DATED this 1st day of July, 2026.

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Exhibit EGW-1

ERIK G. WETMORE — Principal

Mr. Wetmore is a Principal with Turner Wetmore Collins, LLC, a consulting firm serving the regulated energy transportation industry. He has more than thirty-five years of experience advising clients on ratemaking, financial, accounting, economic, and contract interpretation matters, and regularly provides expert testimony before regulatory commissions and courts.

Prior to co-founding Turner Wetmore Collins, LLC in 2003, Mr. Wetmore worked in Ernst & Young's Oil Pipeline Consulting Group and Arthur D. Little's Corporate Finance & Strategy Practice. He holds an M.B.A. in Finance and Economics from the University of Chicago Booth School of Business and a B.A. in Mathematics and Economics from the University of California at Santa Barbara. Mr. Wetmore also earned a Certified Public Accountant license in California.

REPRESENTATIVE EXPERIENCE:

Ratemaking, Regulatory Policy, and Contract Interpretation

- Provided expert testimony on ratemaking, accounting, regulatory policy, and contract interpretation matters before the Alaska Department of Revenue, the British Columbia Utilities Commission ("BCUC"), the California Public Utilities Commission ("CPUC"), the Canada Energy Regulator ("CER"), the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska ("RCA"), and the Superior Court of the State of California.

- Prepared ratemaking analyses and supporting materials for compliance filings in response to regulatory commission rulings.

- Advised clients on settlement negotiations in rate cases before regulatory commissions.

- Developed ratemaking support for tariff rate and toll applications at various regulatory commissions.

- Developed multiple cost-of-service and revenue requirement analytical models.

- Assisted pipeline carriers to develop the "Annual Cost of Service Based Analysis Schedule" for their respective FERC Form No. 6's.

Accounting

- Served as a subject matter expert for industry associations on FERC accounting and reporting practices.

- Advised and assisted pipeline carriers during FERC audits.

- Assisted pipeline carriers in the preparation and development of their FERC Form No. 6 filings.

- Conducted regulatory accounting workshops for FERC staff and pipeline carriers.

- Directed development of FERC Form No. 6 training course for the Liquid Energy Pipeline Association ("LEPA"). Included developing a comprehensive FERC Form No. 6 Training Model that highlighted the interdependence of supporting schedules and financial statements within the FERC Form No. 6.

- Developed depreciation studies approved by the FERC.

- Authored a report for LEPA members that compared and contrasted the Uniform System of Accounts with Generally Accepted Accounting Principles for the LEPA.

- Planned and performed audits of financial statements for multiple clients.

- Taught undergraduate accounting courses at the University of California at Santa Barbara.

Corporate Finance & Business Strategy

- Supported clients in evaluating large-scale capital investment projects, including scenario modeling, cost recovery mechanisms, and regulatory risk assessment.

- Directed a project assessing the strategic and regulatory implications of electric utility restructuring and diversification strategies; presented findings to the CPUC.

- Managed a series of projects focused on renewable energy and energy research, development and demonstration programs for the California Energy Commission.

- Managed project for the Electric Power Research Institute and over twenty-five participating electric utilities that evaluated how technologies need to develop to achieve select business visions. Results used to assist in development of R&D budgets for participating utilities.

- Directed a project evaluating the financial opportunity for a utility to enter the telecommunications market, including assessment of strategic options, regulatory requirements, and financial modeling; the utility subsequently entered a joint venture with a partner identified through the project.

TESTIMONY:

May 2026	Submitted declaration before the CPUC on behalf of SFPP, L.P., Application 26-01-016.
September 2025	Submitted prepared direct testimony before the RCA on behalf of Pikka Transportation Company, TL 1-789.
June 2025	Presented oral testimony before the CPUC on behalf of SFPP, L.P., Application No. 24-01-020, *et al*.
May 2025	Submitted prepared additional supplemental rebuttal testimony before the CPUC on behalf of SFPP, L.P., Application No. 24-01-020, *et al*.
April 2025	Submitted prepared supplemental rebuttal and rebuttal testimony before the CPUC on behalf of SFPP, L.P., Application No. 24-01-020, *et al*.
February 2025	Submitted expert report before the BCUC on behalf of Plateau Pipe Line Ltd.
January 2025	Submitted declaration before the CPUC on behalf of SFPP, L.P., Advice Letter No. 54-O.
December 2024	Submitted affidavit before the FERC on behalf of South Bow (USA), LP, Docket No. IS20-108-001 *et al*.
October 2024	Submitted affidavit before the FERC on behalf of South Bow (USA), LP, Docket No. IS20-108-001 *et al*.
October 2024	Submitted prepared supplemental direct testimony before the CPUC on behalf of SFPP, L.P., Application No. 24-01-020, *et al*.
January 2024	Submitted declaration before the CPUC on behalf of SFPP, L.P., Application 24-01-016.
January 2024	Submitted affidavit before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
December 2023	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, TL52-334.

December 2023	Submitted affidavit before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
January 2023	Submitted declaration before the CPUC on behalf of SFPP, L.P., Application 23-01-016.
January 2023	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, TL49-334.
October 2022	Presented oral testimony before the CER on behalf of PKM Canada North 40 Limited Partnership, RH-001-2022.
August 2022	Submitted reply evidence expert report before the CER on behalf of PKM Canada North 40 Limited Partnership, RH-001-2022.
August 2022	Submitted expert report before the CER on behalf of PKM Canada North 40 Limited Partnership, RH-001-2022.
July 2022	Presented oral testimony before the FERC on behalf of TransCanada Keystone Pipeline, LP, Docket No. IS20-108-001 *et al*.
March 2022	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, TL48-334.
January 2022	Submitted declaration before the CPUC on behalf of SFPP, L.P., Application 22-01-016.
December 2021	Submitted prepared rebuttal testimony before the FERC on behalf of TransCanada Keystone Pipeline, LP, Docket No. IS20-108-001 *et al*.
November 2021	Submitted prepared cross-answering testimony before the FERC on behalf of TransCanada Keystone Pipeline, LP, Docket No. IS20-108-001 *et al*.
November 2021	Submitted prepared rebuttal testimony before the CPUC on behalf of SFPP, L.P., Application No. 21-01-015.
October 2021	Submitted prepared direct testimony before the CPUC on behalf of SFPP, L.P., Application No. 21-01-015.
August 2021	Submitted prepared answering testimony before the FERC on behalf of TransCanada Keystone Pipeline, LP, Docket No. IS20-108-001 *et al*.

July 2021	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, TL47-334.
March 2021	Submitted expert report before the BCUC on behalf of PKM Canada (Jet Fuel) Inc., Project No. 1598984.
January 2021	Submitted declaration before the CPUC on behalf of SFPP, L.P., Application 21-01-015.
October 2020	Presented oral testimony before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
July 2020	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. OR14-35 and OR14-36.
May 2020	Submitted prepared surrebuttal testimony before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
February 2020	Submitted prepared answering testimony before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
November 2019	Submitted prepared answering testimony before the FERC on behalf of Colonial Pipeline Company, Docket No. OR18-7-002 *et al*.
August 2019	Submitted expert report before the BCUC on behalf of Kinder Morgan Canada (Jet Fuel) Inc., Project No. 1598984.
June 2019	Submitted expert report before the BCUC on behalf of Kinder Morgan Canada (Jet Fuel) Inc., Project No. 1598984.
May 2019	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. IS08-390-004, -006, -007.
February 2019	Presented oral deposition testimony before the Alaska Department of Revenue on behalf of ConocoPhillips Company, OAH 16-0582 and OAH 17-0722.
September 2018	Submitted expert report before the Alaska Department of Revenue on behalf of ConocoPhillips Company, OAH 16-0582 and OAH 17-0722.
July 2018	Submitted prepared direct testimony before the RCA on behalf of PTE Pipeline LLC, Docket No. P-18-018.

July 2018	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, TL46-334.
May 2018	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. IS08-390-004, -006, -007.
May 2018	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. IS09-437-000 and IS10-572-000.
September 2017	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket No. OR16-6-000.
February 2017	Presented oral testimony before the FERC on behalf of SFPP, L.P., Docket No. OR16-6-000.
October 2016	Submitted prepared answering testimony before the FERC on behalf of SFPP, L.P., Docket No. OR16-6-000.
August 2016	Submitted prepared answering testimony before the FERC on behalf of SFPP, L.P., Docket No. OR16-6-000.
April 2016	Submitted affidavit before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket Nos. P-08-009, P-09-010, and P-10-010.
April 2016	Submitted affidavit before the RCA on behalf of ExxonMobil Pipeline Company, Docket Nos. P-08-013, P-09-015, and P-11-005.
April 2016	Submitted affidavit before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket Nos. P-09-005, P-09-012, and P-10-013.
April 2016	Submitted affidavit before the RCA on behalf of Unocal Pipeline Company, Docket Nos. P-09-006, P-10-005, and P-11-009.
March 2016	Submitted affidavit before the FERC on behalf of Seaway Crude Pipeline Company LLC, Docket No. IS12-226-000.
February 2016	Submitted supplemental affidavit before the FERC on behalf of the Trans Alaska Pipeline System Carriers, Docket No. IS09-348-004, *et al*.
January 2016	Submitted affidavit before the FERC on behalf of the Trans Alaska Pipeline System Carriers, Docket No. IS09-348-004, *et al*.

September 2015	Submitted prepared direct testimony before the RCA on behalf of Point Thomson Export Pipeline, Docket No. P-12-015.
April 2015	Submitted verified statement before the FERC on behalf of SFPP, L.P., Docket Nos. IS08-390-004, -006, -007.
April 2015	Submitted verified statement before the FERC on behalf of SFPP, L.P., Docket Nos. IS09-437-000 and IS10-572-000.
March 2015	Presented oral testimony before the FERC on behalf of Buckeye Pipe Line Company, L.P., Docket No. OR12-28-001.
March 2015	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, Docket No. P-15-006.
December 2014	Submitted prepared answering testimony before the FERC on behalf of Buckeye Pipe Line Company, L.P., Docket No. OR12-28-001.
October 2014	Presented oral deposition testimony before the Superior Court of the State of California for the County of Los Angeles on behalf of Phillips 66 Company, Case No. BC518730.
October 2014	Submitted prepared answering testimony before the FERC on behalf of Buckeye Pipe Line Company, L.P., Docket No. OR12-28-001.
September 2014	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. OR14-35 and OR14-36.
August 2014	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-14-024.
July 2014	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-14-023.
July 2014	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. OR14-35 and OR14-36.
November 2013	Submitted prepared direct testimony before the RCA on behalf of Oliktok Pipeline Company, Docket No. P-13-013.
July 2013	Submitted declaration before the CPUC on behalf of Calnev Pipe Line LLC, Application 13-07-013.

July 2013	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-13-010.
May 2013	Presented oral testimony before the CPUC on behalf of SFPP, L.P., Application No. 12-01-015.
April 2013	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-13-009.
April 2013	Submitted prepared rebuttal testimony before the CPUC on behalf of SFPP, L.P., Application No. 12-01-015.
March 2013	Presented oral testimony before the FERC on behalf of Seaway Crude Pipeline Company LLC, Docket No. IS12-226-000.
February 2013	Submitted prepared supplemental reply testimony before the CPUC on behalf of SFPP, L.P., Application No. 12-01-015.
February 2013	Submitted prepared rebuttal testimony before the FERC on behalf of Seaway Crude Pipeline Company LLC, Docket No. IS12-226-000.
February 2013	Submitted prepared reply testimony before the CPUC on behalf of SFPP, L.P., Application No. 12-01-015.
January 2013	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-12-016.
December 2012	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-12-017.
November 2012	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket Nos. IS09-437-000 and IS10-572-000.
November 2012	Submitted prepared direct testimony before the CPUC on behalf of SFPP, L.P., Application No. 12-01-015.
August 2012	Submitted prepared direct testimony before the FERC on behalf of Seaway Crude Pipeline Company LLC, Docket No. IS12-226-000.
July 2012	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-12-017.
June 2012	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-12-016.

June 2012	Submitted affidavit before the FERC on behalf of SFPP, L.P., Docket No. IS12-388-000.
December 2011	Submitted declaration before the CPUC on behalf of Calnev Pipe Line LLC, Application 08-06-0090.
December 2011	Submitted prepared direct testimony before the RCA on behalf of Unocal Pipeline Company, Docket No. P-11-022.
August 2011	Submitted prepared reply testimony before the RCA on behalf of the Indicated Trans Alaska Pipeline System Carriers, Docket No. P-08-9, *et al.*
June 2011	Submitted prefiled direct testimony before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket No. P-11-12.
May 2011	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-11-11.
February 2011	Submitted prepared direct testimony before the RCA on behalf of Unocal Pipeline Company, Docket No. P-11-9.
December 2010	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-11-6.
November 2010	Presented oral testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS09-348.
October 2010	Submitted prepared reply testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No IS09-348.
August 2010	Submitted prefiled direct testimony before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket No. P-10-13.
July 2010	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-10-10.
June 2010	Submitted prepared answering testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS09-348.
April 2010	Submitted prepared direct testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS09-348.

December 2009	Submitted prepared direct testimony before the RCA on behalf of Unocal Pipeline Company, Docket No. P-10-5.
November 2009	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-09-15.
September 2009	Submitted prepared direct testimony before the CPUC on behalf of Calnev Pipe Line LLC, Application No. 08-06-009.
August 2009	Submitted prefiled direct testimony before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket No. P-09-12.
July 2009	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-09-10.
December 2008	Submitted prepared direct testimony before the RCA on behalf of Unocal Pipeline Company, Docket No. P-09-6.
December 2008	Submitted affidavit before the RCA on behalf of Unocal Pipeline Company, Docket No. P-09-6.
December 2008	Submitted prefiled direct testimony before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket No. P-09-5.
December 2008	Submitted affidavit before the RCA on behalf of Koch Alaska Pipeline Company, LLC, Docket No. P-09-5.
November 2008	Submitted prepared direct testimony before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-08-13.
November 2008	Submitted affidavit before the RCA on behalf of ExxonMobil Pipeline Company, Docket No. P-08-13.
October 2008	Submitted prepared direct testimony before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-08-9.
October 2008	Submitted affidavit before the RCA on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. P-08-9.
February 2008	Submitted affidavit before the FERC on behalf of White Cliffs Pipeline, L.L.C., Docket No. OR08-8-000.
June 2007	Submitted prepared direct testimony before the FERC on behalf of Calnev Pipe Line LLC, Docket No. IS06-296-002.

November 2006	Presented oral testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket Nos. IS05-80-002 and IS06-63-000.
November 2006	Presented oral testimony before the FERC on behalf of ExxonMobil Pipeline Company, Docket Nos. IS05-72-002 and IS06-71-000.
November 2006	Presented oral testimony before the FERC on behalf of Koch Alaska Pipeline Company, LLC, Docket Nos. IS05-96-002 and IS06-66-000.
November 2006	Presented oral testimony before the FERC on behalf of Unocal Pipeline Company, Docket Nos. IS05-107-001 and IS06-82-000.
June 2006	Submitted affidavit before the FERC on behalf of Rocky Mountain Pipeline System LLC, Docket Nos. IS06-342-000 and IS06-343-000.
May 2006	Submitted prepared answering testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS05-80-002 and IS06-63-000.
April 2006	Submitted prepared supplemental direct testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS06-63-000.
April 2006	Submitted prepared supplemental direct testimony before the FERC on behalf of ExxonMobil Pipeline Company, Docket No. IS06-71-000.
April 2006	Submitted prepared supplemental direct testimony before the FERC on behalf of Koch Alaska Pipeline Company, LLC, Docket No. IS06-66-000.
April 2006	Submitted prepared supplemental direct testimony before the FERC on behalf of Unocal Pipeline Company, Docket No. IS06-82-000.
December 2005	Submitted prepared direct testimony before the FERC on behalf of ConocoPhillips Transportation Alaska, Inc., Docket No. IS05-80-002.
December 2005	Submitted prepared direct testimony before the FERC on behalf of ExxonMobil Pipeline Company, Docket No. IS05-72-002.
December 2005	Submitted prepared direct testimony before the FERC on behalf of Koch Alaska Pipeline Company, LLC, Docket No. IS05-96-002.

December 2005 Submitted prepared direct testimony before the FERC on behalf of Unocal Pipeline Company, Docket No. IS05-107-001.

REPRESENTATIVE PUBLICATIONS AND PRESENTATIONS:

"Depreciation Studies," Council of Petroleum Accountants Societies—Anchorage. Alaska Group (September 2025)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, Calgary, Alberta (September 2025)

"Page 700 Cost of Service Workshop," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2025)

"FERC Audits: Accounting Findings," LEPA, Annual Business Conference, Nashville, Tennessee (September 2024)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, Minneapolis, Minnesota (September 2023)

"Form 6 201 Advanced Session," LEPA, Annual Business Conference, Annual Business Conference, Minneapolis, Minnesota (September 2023)

"FERC Audit Report Findings," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2023)

"Financial Statements and Supporting Schedules Important for Page 700," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2023)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, San Diego, California (September 2022)

"Form 6 201 Advanced Session," LEPA, Annual Business Conference, Annual Business Conference, Atlanta, Georgia (September 2021)

"General Information Statements and Notes to Financial Statements," LEPA, FERC Form 6 No. Training, Virtual (February 2021)

"Page 700 Workshop," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2020)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, San Antonio, Texas (September 2019)

"General Information Statements and Notes to Financial Statements," LEPA, FERC Form 6 No. Training, Houston, Texas (February 2019)

"Form 6 201 Advanced Session," LEPA, Annual Business Conference, Denver, Colorado (September 2018)

"General Information Statements and Notes to Financial Statements," LEPA, FERC Form 6 No. Training, Houston, Texas (February 2018)

"Form 6 201 Advanced Session," LEPA, Annual Business Conference, Seattle, Washington (September 2017)

"Cost of Service Concepts," LEPA, Annual Business Conference, Chicago, Illinois (September 2016)

"Page 700 Workshop," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2016)

"Overhead Allocations," LEPA, Annual Business Conference, Atlanta, Georgia (September 2015)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, Coeur d'Alene, Idaho (September 2014)

"FERC Hearings and Settlements," LEPA, Annual Business Conference, Newport Beach, California (September 2013)

"Cost of Service Concepts," LEPA, Annual Business Conference, Savannah, Georgia (September 2012)

"Financial Statements and Supporting Schedules Important for Page 700," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2012)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, Denver Colorado (September 2011)

"Page 700 Workshop," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2011)

"Form 6 201," LEPA, Annual Business Conference, Atlanta, Georgia (September 2010)

"General Information Statements and Notes to Financial Statements," LEPA, FERC Form 6 No. Training, Houston, Texas (January 2010)

"Cost of Service Concepts," LEPA, Annual Business Conference, San Diego, California (September 2009)

"Financial Statements and Supporting Schedules Important for Page 700," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2009)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference (September 2008)

"Page 700 Workshop," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2008)

"Understanding and Applying FERC Accounting Standards," LEPA, Annual Business Conference, Los Angeles, California (September 2007)

"Financial Statements and Supporting Schedules Important for Page 700," LEPA, FERC Form No. 6 Training, Houston, Texas (February 2007)

"Acquisition Due Diligence," LEPA, Annual Business Conference, Minneapolis, Minnesota (May 2006)

Key Differences Between the Uniform System of Accounts and Generally Accepted Accounting Principles, developed for LEPA (September 2005)

"Dissecting the FERC Form No. 6," LEPA, Annual Business Conference, New Orleans, Louisiana (May 2005)

"Workpaper Documentation to Support Tariff Filings," LEPA, Annual Business Conference, Baltimore, Maryland (May 2003)

"The Role of Distributed Generation in the New Electric Distribution Business," California Public Utilities Commission, San Francisco, California (February 1999)

Distribution System Redesign (with several authors), developed for Electric Power Research Institute, EPRI TR-111683, Palo Alto, California (December 1998)

"The New Electric Distribution Company: Six Future Visions," California Public Utilities Commission, San Francisco, California (November 1998)

EMPLOYMENT HISTORY:

Principal	Turner Wetmore Collins, LLC Danville, California	2003 - Present
Director	Portal Software Cupertino, California	1999 - 2003
Manager	Arthur D. Little San Francisco, California	1997 - 1999
Manager	Ernst & Young (EY) Oil Pipeline Consulting Group San Francisco, California	1992 - 1995
Sr. Auditor	Ernst & Young (EY) San Francisco, California	1990 - 1992

EDUCATION & CERTIFICATION:

University of Chicago Booth School of Business M.B.A., Concentrations in Finance and Economics	1997
Certified Public Accountant (CPA), California *(Currently on inactive status)*	1993
University of California, Santa Barbara B.A., Mathematics and Economics	1990

Exhibit EGW-2

Oliktok Pipeline Company

Supporting Information for Revenue Requirement

Table of Contents

Name of Respondent Oliktok Pipeline Company	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report 02/18/2026	Year/Period of Report End of: 2025/ Q4

Comparative Balance Sheet Statement

Line No.	Item (a)	Reference Page No. for Annual (b)	Current Year End of Quarter/Year Balance (in dollars) (c)	Prior Year End Balance 12/31 (in dollars) (d)
	CURRENT ASSETS			
1	Cash (10)			
2	Special Deposits (10-5)			
3	Temporary Investments (11)			
4	Notes Receivable (12)			
5	Receivables from Affiliated Companies (13)	200	399,264	2,509,611
6	Accounts Receivable (14)		6,049	62,112
7	Accumulated Provision For Uncollectible Accounts (14-5)			
8	Interest and Dividends Receivable (15)			
9	Oil Inventory (16)			
10	Material and Supplies (17)		312,755	280,503
11	Prepayment (18)		807,154	807,154
12	Other Current Assets (19)			
13	Deferred Income Tax Assets (19-5)	230		27,000
14	TOTAL Current Assets (Total of lines 1 thru 13)		1,525,222	3,686,380
	INVESTMENTS AND SPECIAL FUNDS			
	Investments in Affiliated Companies (20):			
15	Stocks	202		
16	Bonds	202		
17	Other Secured Obligations	202		
18	Unsecured Notes	202		
19	Investment Advances	202		
20	Undistributed Earnings from Certain Invest. in Acct. 20	204		
	Other Investments (21):			
21	Stocks			
22	Bonds			
23	Other Secured Obligations			
24	Unsecured Notes			
25	Investment Advances			

Comparative Balance Sheet Statement

Line No.	Item (a)	Reference Page No. for Annual (b)	Current Year End of Quarter/Year Balance (in dollars) (c)	Prior Year End Balance 12/31 (in dollars) (d)
26	Sinking and other funds (22)			
27	TOTAL Investment and Special Funds (Total lines 15 thru 26)		0	0
	TANGIBLE PROPERTY			
28	Carrier Property (30)	213 & 215	54,337,353	44,829,833
29	(Less) Accrued Depreciation-Carrier Property (31)	216 & 217	20,722,451	19,210,117
30	(Less) Accrued Amortization-Carrier Property (32)			
31	Net Carrier Property (Line 28 less 29 and 30)		33,614,902	25,619,716
32	Operating Oil Supply (33)			
33	Noncarrier Property (34)	220		
34	(Less) Accrued Depreciation-Noncarrier Property (35)			
35	Net Noncarrier Property (Line 33 less 34)		0	0
36	TOTAL Tangible Property (Total of lines 31, 32, and 35)		33,614,902	25,619,716
	OTHER ASSETS AND DEFERRED CHARGES			
37	Organization Costs and Other Intangibles (40)			
38	(Less) Accrued Amortization of Intangibles (41)			
40	Miscellaneous Other Assets (43)			
41	Other Deferred Charges (44)	221		
42	Accumulated Deferred Income Tax Assets (45)	230	3,141,000	3,116,000
43	Derivative Instrument Assets (46)			
44	Derivative Instrument Assets - Hedges (47)			
45	TOTAL Other Assets and Deferred Charges (37 thru 44)		3,141,000	3,116,000
46	TOTAL Assets (Total of lines 14, 27, 36 and 45)		38,281,124	32,422,096
	CURRENT LIABILITIES			
47	Notes Payable (50)			
48	Payables to Affiliated Companies (51)	225	6,744,218	726,712
49	Accounts Payable (52)			
50	Salaries and Wages Payable (53)			
51	Interest Payable (54)			
52	Dividends Payable (55)			

Comparative Balance Sheet Statement				
Line No.	**Item (a)**	**Reference Page No. for Annual (b)**	**Current Year End of Quarter/Year Balance (in dollars) (c)**	**Prior Year End Balance 12/31 (in dollars) (d)**
53	Taxes Payable (56)		11,938	15,531
54	Long-Term Debt - Payable Within One Year (57)	226		
55	Other Current Liabilities (58)		1,500,676	1,966,435
56	Deferred Income Tax Liabilities (59)	230		
57	TOTAL Current Liabilities (Total of lines 47 thru 56)		8,256,832	2,708,678
	NONCURRENT LIABILITIES			
58	Long-Term Debt - Payable After One Year (60)	226		
59	Unamortized Premium on Long-Term Debt (61)			
60	(Less) Unamortized Discount and Interest on Long-Term Debt (62)			
61	Other Noncurrent Liabilities (63)			
62	Accumulated Deferred Income Tax Liabilities (64)	230	4,059,000	4,059,000
63	Derivative Instrument Liabilities (65)			
64	Derivative Instrument Liabilities - Hedges (66)			
65	Asset Retirement Obligations (67)		11,127,805	10,533,455
66	TOTAL Noncurrent Liabilities (Total of lines 58 thru 65)		15,186,805	14,592,455
67	TOTAL Liabilities (Total of lines 57 and 66)		23,443,637	17,301,133
	STOCKHOLDERS' EQUITY			
68	Capital Stock (70)	251	1,000	1,000
69	Premiums on Capital Stock (71)			
70	Capital Stock Subscriptions (72)			
71	Additional Paid-In Capital (73)	254	14,474,712	14,474,712
72	Appropriated Retained Income (74)	118		
73	Unappropriated Retained Income (75)	119	361,775	645,251
74	(Less) Treasury Stock (76)			
75	Accumulated Other Comprehensive Income (77)	116		
76	TOTAL Stockholders' Equity (Total of lines 68 thru 75)		14,837,487	15,120,963
77	TOTAL Liabilities and Stockholders' Equity (Total of lines 67 and 76)		38,281,124	32,422,096

Name of Respondent Oliktok Pipeline Company	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report 02/18/2026	Year/Period of Report End of: 2025/ Q4

Income Statement

Line No.	Item (a) * Less applicable income taxes as reported on page 122	Reference Page No. in Annual Report (b)	Total current year to date Balance for Quarter/Year (c)	Total prior year to date Balance for Quarter/Year (d)	Current 3 months ended Quarterly only no 4th Quarter (e)	Prior 3 months ended Quarterly only no 4th Quarter (f)
	ORDINARY ITEMS - Carrier Operating Income					
1	Operating Revenues (600)	301	8,022,184	11,597,706		
2	(Less) Operating Expenses (610)	302	8,300,546	7,703,398		
3	Net Carrier Operating Income		(278,362)	3,894,308		
	Other Income and Deductions					
4	Income (Net) from Noncarrier Property (620)	335				
5	Interest and Dividend Income (From Investment under Cost Only) (630)	336	38,662	2,007,855		
6	Miscellaneous Income (640)	337	(267)			
7	Unusual or Infrequent Items--Credits (645)					
8	(Less) Interest Expense (650)		41,509			
9	(Less) Miscellaneous Income Charges (660)	337				
10	(Less) Unusual or Infrequent Items--Debit (665)					
11	Dividend Income (From Investments under Equity Only)					
12	Undistributed Earnings (Losses)	205				
13	Equity in Earnings (Losses) of Affiliated Companies (Total Lines 11 and 12)		0			
14	TOTAL Other Income and Deductions (Total Lines 4 thru 10 and 13)		(3,114)	2,007,855		
15	Ordinary Income before Federal Income Taxes (Line 3 +/- 14)		(281,476)	5,902,163		
16	(Less) Income Taxes on Income from Continuing Operations (670)			1,378,000		
17	(Less) Provision for Deferred Taxes (671)	230	2,000	(137,000)		

Income Statement

Line No.	Item (a) * Less applicable income taxes as reported on page 122	Reference Page No. in Annual Report (b)	Total current year to date Balance for Quarter/Year (c)	Total prior year to date Balance for Quarter/Year (d)	Current 3 months ended Quarterly only no 4th Quarter (e)	Prior 3 months ended Quarterly only no 4th Quarter (f)
18	Income (Loss) from Continuing Operations (Total Lines 15 thru 17)		(283,476)	4,661,163		
	Discontinued Operations					
19	Income (Loss) from Operations of Discontinued Segments (675)*					
20	Gain (Loss) on Disposal of Discontinued Segments (676)*					
21	TOTAL Income (Loss) from Discontinued Operations (Lines 19 and 20)		0			
22	Income (Loss) before Extraordinary Items (Total Lines 18 and 21)		(283,476)	4,661,163		
	EXTRAORDINARY ITEMS AND ACCOUNT CHANGES					
23	Extraordinary Items -- Net -- (Debit) Credit (680)	337				
24	Income Taxes on Extraordinary Items -- Debit (Credit) (695)	337				
25	Provision for Deferred Taxes -- Extraordinary Items (696)	230				
26	TOTAL Extraordinary Items (Total Lines 23 thru 25)		0			
27	Cumulative Effect of Changes in Accounting Principles (697)*					
28	TOTAL Extraordinary Items and Accounting Changes -- (Debit) Credit (Line 26 + 27)		0			
29	Net Income (Loss) (Total Lines 22 and 28)		(283,476)	4,661,163		

Name of Respondent Oliktok Pipeline Company	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report 02/18/2026	Year/Period of Report End of: 2025/ Q4

Unappropriated Retained Income Statement

Line No.	Item (a)	Reference page no. for Year (b)	Current Quarter/Year (in dollars) (c)	Previous Quarter/Year (in dollars) (d)
	UNAPPROPRIATED RETAINED INCOME			
1	Balances at Beginning of Year		645,251	36,420,991
	CREDITS			
2	Net Balance Transferred from Income (700)	114	(283,476)	4,661,163
3	Prior Period Adjustments to Beginning Retained Income (705)			
4	Other Credits to Retained Income (710)*	337		
5	TOTAL (Lines 2 thru 4)		(283,476)	4,661,163
	DEBITS			
6	Net Balance Transferred from Income (700)	114		
7	Other Debits to Retained Income (720)*	337		
8	Appropriations of Retained Income (740)	118		
9	Dividend Appropriations of Retained Income (750)	121		40,436,903
10	TOTAL (lines 6 thru 9)		0	40,436,903
11	Net Increase (Decrease) During Year (Line 5 minus line 10)		(283,476)	(35,775,740)
12	Balances at End of Year (Lines 1 and 11)		361,775	645,251
13	Balance from Line 20	204	0	
14	TOTAL Unapprop. Retained Inc. and Equity in Undistr. Earnings. (Losses) of Affil. Comp. at End of Year (Lines 12 & 13)		361,775	645,251
	*Amount of Assigned Federal Income Tax Consequences			
15	Account No. 710			
16	Account No. 720			
	EQUITY IN UNDISTRIBUTED EARNINGS (LOSSES) OF AFFILIATED COMPANIES			
17	Balances at Beginning of Year	204		
18	Net Balance transferred from Income (700)	114		
19	Other Credits (Debits)			
20	Balances at End of Reporting Period/Year	204	0	

Oliktok Pipeline Company
Proposed Rate Change
($ per Mcf)

Line No.	Description	Source	Amount
1	Proposed Rate - GHP	Schedule 5, Lns. (22 / 7)	$0.914
2	Proposed Rate - GSP	Schedule 5, Lns. (23 / 8)	$1.464
3	Proposed Rate - KRU	Schedule 5, Lns. (24 / 9)	$1.528
	Comparison with Most Recently Approved Rates		
4	Most Recent Approved Rate - GHP	1/	$0.346
5	Most Recent Approved Rate - GSP	1/	$0.555
6	Most Recent Approved Rate - KRU	1/	$0.580
7	Proposed Rate Change - GHP	Lns. (1 - 4)	$0.568
8	Proposed Rate Change - GSP	Lns. (2 - 5)	$0.909
9	Proposed Rate Change - KPU	Lns. (3 - 6)	$0.948
10	Proposed Rate Change - GHP (%)	Lns. (7 / 4)	164%
11	Proposed Rate Change - GSP (%)	Lns. (8 / 5)	164%
12	Proposed Rate Change - KRU (%)	Lns. (9 / 6)	163%

1/ On December 18, 2025, the Commission approved the tariff rates, with an effective date of January 1, 2026.

Oliktok Pipeline Company
Revenue Requirement

Exhibit EGW-2
Schedule 5

Line No.	Description	Source	Normalized Test-Year
1	Operating Expenses ($000's)	Schedule 6, Page 1 of 2, Ln. 19	$6,445
2	Depreciation Expense ($000's)	Schedule 10, Ln. 15	$2,169
3	Amortization of AFUDC ($000's)	Workpaper 1.2, Ln. 10	$123
4	Return on Rate Base ($000's)	Schedule 12, Ln. 3	$2,573
5	Income Tax Allowance ($000's)	Schedule 8, Ln. 14	$658
6	Total Revenue Requirement ($000's)	Sum Lns. (1 to 5)	$11,968
7	GHP Deliveries (thousand Mcf)	Choudhury Testimony	0
8	GSP Deliveries (thousand Mcf)	Choudhury Testimony	4,536
9	KRU Deliveries (thousand Mcf)	Choudhury Testimony	3,482
10	Total Deliveries (thousand Mcf)	Sum Lns. (7 to 9)	8,017
11	GHP Distance (miles)	Company Records	15.85
12	GSP Distance (miles)	Company Records	26.79
13	KRU Distance (miles)	Company Records	28.06
14	GHP Deliveries (thousand Mcf-miles)	Lns. (7 * 11)	0
15	GSP Deliveries (thousand Mcf-miles)	Lns. (8 * 12)	121,508
16	KRU Deliveries (thousand Mcf-miles)	Lns. (9 * 13)	97,713
17	Total Deliveries (thousand Mcf-miles)	Sum Lns. (14 to 16)	219,221
18	Non-Distance Related Costs ($000's)	Schedule 6, Page 1 of 2, Ln. 20	$930
19	Non-Distance Related Costs ($/Mcf)	Lns. (18 / 10)	$0.12
20	Total Revenue Requirement ($000's)	Ln. 6	$11,968
21	Remaining Revenue Requirement ($000's)	Lns. (20 - 18)	$11,038
22	GHP Portion of Revenue Requirement ($000's)	Lns. ((19*7)+(21*(14/17)))	$0
23	GSP Portion of Revenue Requirement ($000's)	Lns. ((19*8)+(21*(15/17)))	$6,644
24	KRU Portion of Revenue Requirement ($000's)	Lns. ((19*9)+(21*(16/17)))	$5,324
25	Total Revenue Requirement ($000's)	Sum Lns. (22 to 24)	$11,968
26	Projected Revenue with Proposed Rates ($000's)	Lns. (7 to 9) * Schedule 4, Lns. (1 to 3)	$11,960
27	Revenue Surplus (Deficit) ($000's)	Lns. (26 - 25)	($7)
28	Revenue Surplus (Deficit) (%)	Lns. (27 / 25)	0%

Line No. (a)	Account No. (b)	Description (c)	Historical Test Year 2025 (d) 1/	Pro Forma Adjustments 1 (e) 2/	Normalized Test-Year (f) (d) thru (e)
		OPERATIONS			
1	300	Salaries and Wages	$862		$862
2	310	Supplies and Expenses	$85		$85
3	320	Outside Services	$286		$286
4	330	Fuel and Power	$1		$1
5	340	Oil Losses and Shorts	$0		$0
6	350	Rentals	$1,240		$1,240
7	390	Other Expenses	$0		$0
8		Total Operations	$2,474	$0	$2,474
		GENERAL			
9	500	Salaries and Wages	$0		$0
10	510	Supplies and Expenses	$0		$0
11	520	Outside Services	$0	$122	$122
12	530	Rentals	$158		$158
13	550	Pensions and Benefits	$1		$1
14	560	Insurance	$0		$0
15	570	Casualty and Other Losses	$0		$0
16	580	Pipeline Taxes	$821		$821
17	590	Other Expenses	$2,869		$2,869
18		Total General	$3,849	$122	$3,971
19		Grand Totals	$6,323	$122	$6,445
20		Non-Distance Related Costs	$930		$930

1/ Per Oliktok's 2025 Annual Report and Exhibit RDC-2.
2/ Reflects $0.367 million of estimated rate case expense amortized over 3 years.

Line No.	Description	Historical Test-Year (a) 1/	Pro Forma Adjustments (b)	Normalized Test-Year (c) (a) + (b)
1	Total Deliveries (thousand Mcf)	15,639	(7,622)	8,017
2	Operating Revenues ($000's)	$8,022	$3,938	$11,960 2/

1/ Per 2025 Annual Report.
2/ Normalized Test-Year revenues per Schedule 5, Ln. 26.

Line No.	Description	Historical Test Year 2025	Pro Forma Adjustment	Normalized Test-Year
1	Rate Case Expense	$0	$122	$122

Reflects $0.367 million of estimated rate case expense amortized over 3 years.

Source of Computation: Schedule 6, Page 1 of 2.

Line No.	Description	Historical Test Year 2025	Pro Forma Adjustments	Normalized Test-Year	
1	Carrier Property in Service	$68,892	$9,006	$77,899	1/
2	Accumulated Depreciation of Carrier Property	($44,072)	($31)	($44,104)	2/
3	Net AFUDC	$1,698	($1)	$1,697	3/
4	Working Capital	$855	$0	$855	
5	Accumulated Deferred Income Taxes	($4,952)	$0	($4,952)	
6	13-Month Averge Rate Base	$22,422	$8,974	$31,396	

1/ Reflects Sep. 2025 property addition in service for all of 2025.
2/ Reflects incremental depreciation expense assuming Sep. 2025 property addition in service for all of 2025.
3/ Reflects incremental AFUDC amortization expense assuming Sep. 2025 property addition in service for all of 2025.

Source of Computation: Schedule 9.1.

Line No.	Description	Historical Test Year 2025	Pro Forma Adjustment	Normalized Test-Year
1	Depreciation Expense	$1,763	$407	$2,169

Reflects an annualized amount of depreciation expense assuming Sep. 2025 property addition in service for entire test year.

Source of Computation: Schedule 10.

Line No.	Description	Historical Test Year 2025	Pro Forma Adjustment	Normalized Test-Year
1	AFUDC Amortization Expense	$110	$13	$123

Reflects an annualized amount of amortization expense assuming Sep. 2025 property addition in service for entire test year.

Source of Computation: Workpaper 1.2.

Line No.	Description	Historical Test Year 2025	Pro Forma Adjustment	Normalized Test-Year
1	GHP Deliveries (thousand Mcf)	8	(8)	0
2	GSP Deliveries (thousand Mcf)	8	4,527	4,536
3	KRU Deliveries (thousand Mcf)	15,622	(12,140)	3,482
4	Total Deliveries (thousand Mcf)	15,639	(7,622)	8,017

Reflects actual 2026 volumes through June 21 and projected volumes for remainder of the year.

Source: company data and shipper projections.

Oliktok Pipeline Company
Income Tax Allowance
($000's)

Line No.	Description	Source	Normalized Test-Year
1	Return on Equity Rate Base	Schedule 12, Ln. 10	$1,682
2	Amortization of Equity AFUDC	Workpaper 1.2, Ln. 4	$82
3	Amortization of TEFRA Adjustment	Workpaper 2.2, Ln. 3	$5
4	Amortization of Deferred Tax Adjustments	Workpaper 2.1, Ln. 18	$32
5	Subtotal for Federal Income Tax Allowance	Lns. (1 + 2 + 3 - 4)	$1,737
6	Federal Income Tax Rate	IRC	21.00%
7	Net-to-Tax Multiplier - Federal Income Tax	Ln. 6 / (1 - Ln. 6)	26.58%
8	Federal Income Tax Allowance	Lns. ((5 * 7) - 4)	$430
9	Amortization of Equity AFUDC	Ln. 2	$82
10	Subtotal for State Income Tax Allowance	Lns. (1 + 8 + 9)	$2,194
11	Alaska State Income Tax Rate	AK Stat.	9.40%
12	Net-to-Tax Multiplier - State Income Tax	Ln. 11 / (1 - Ln. 11)	10.38%
13	State Income Tax Allowance	Ln. (10 * 12)	$228
14	Total Income Tax Allowance	Lns. (8 + 13)	$658

Oliktok Pipeline Company
Annual Rate Base
($000's)

Line No.	Description	Source	Dec 2022	Dec 2023	Dec 2024	Dec 2025
1	Carrier Property in Service	Schedule 10, Ln. 5	$64,778	$64,890	$64,890	$77,899
2	Accumulated Depreciation of Carrier Property	Schedule 10, Ln. 18	$40,482	$41,835	$43,191	$44,954
3	Net Carrier Property in Service	Lns. (1 - 2)	$24,296	$23,055	$21,699	$32,945
4	Net AFUDC	Workpaper 1.2, Ln. 11	$1,725	$1,636	$1,540	$1,856
5	Working Capital	Annual Report		$1,086	$1,088	$1,120
6	Accumulated Deferred Income Taxes	Workpaper 2.1, Ln. 21		$4,799	$4,888	$5,015
7	Rate Base	Lns. (3 + 4 + 5 - 6)		$20,978	$19,438	$30,906

Line No.	Description	Source	Dec 31, 2024 1/	Jan 1, 2025	Feb 1, 2025	Mar 1, 2025	Apr 1, 2025	May 1, 2025	Jun 1, 2025
1	Carrier Property in Service, BOY	Prior Ln. 4		$64,890	$64,890	$64,890	$64,890	$64,890	$64,890
2	Additions to Carrier Property in Service	Exh. RDC-3		$0	$0	$0	$0	$0	$0
3	Retirements of Carrier Property in Service	Exh. RDC-3		$0	$0	$0	$0	$0	$0
4	Carrier Property in Service, EOY	Sum Lns. (1 thru 3)	$64,890	$64,890	$64,890	$64,890	$64,890	$64,890	$64,890
5	Accumulated Depreciation of Carrier Property	2/	$43,191	$43,191	$43,338	$43,485	$43,632	$43,779	$43,925
6	Net Carrier Property in Service	Lns. (4 - 5)	$21,699	$21,699	$21,552	$21,405	$21,258	$21,111	$20,964
7	Net AFUDC	3/	$1,540	$1,540	$1,566	$1,593	$1,619	$1,645	$1,672
8	Working Capital	Exh. RDC-4	$1,088	$1,088	$1,015	$948	$853	$813	$746
9	Accumulated Deferred Income Taxes	4/	$4,888	$4,888	$4,899	$4,910	$4,920	$4,931	$4,941
10	Month-End Rate Base	Lns. (6 + 7 + 8 - 9)	$19,438	$19,438	$19,234	$19,036	$18,810	$18,639	$18,441
11	13-Month Avg. Rate Base for Historical Test-Year	Average Ln. 10							
	Pro Forma Adjustments to Rate Base								
12	Annualize Sep. 2025 Property Addition	5/		$13,009	$13,009	$13,009	$13,009	$13,009	$13,009
13	Synchronization Adjustment - Deprec.	6/		($45)	($45)	($45)	($45)	($45)	($45)
14	Synchronization Adjustment - Amort. AFUDC	7/		($1)	($1)	($1)	($1)	($1)	($1)
15	Net Pro Forma Adjustment to Rate Base	Sum Lns. (12 thru 14)		$12,962	$12,962	$12,962	$12,962	$12,962	$12,962
16	Month-End Rate Base - After Net Pro Forma Adj.	Lns. (10 + 15)		$32,400	$32,196	$31,998	$31,772	$31,601	$31,403
13	13-Month Avg. Rate Base for Normalized Test-Year	Average Ln. 16							

1/ Amounts per Schedule 9, year-end 2024 column.
2/ 2025 activity reported on Schedule 9, Ln. 2 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
3/ 2025 activity reported on Schedule 9, Ln. 4 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
4/ 2025 activity reported on Schedule 9, Ln. 6 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
5/ Reflects Sep. 2025 property addition (see Ln. 2) in service for all of 2025.
6/ Reflects incremental depreciation expense assuming Sep. 2025 property addition in service for all of 2025. Incremental amount per Schedule 10, Ln. 20.
7/ Reflects incremental AFUDC amortization expense assuming Sep. 2025 property addition in service for all of 2025. Incremental amount per Workpaper 1.2, Ln. 12.

Line No.	Description	Source	Jul 1, 2025	Aug 1, 2025	Sep 1, 2025	Oct 1, 2025	Nov 1, 2025	Dec 1, 2025	Dec 31, 2025
1	Carrier Property in Service, BOY	Prior Ln. 4	$64,890	$64,890	$64,890	$64,890	$77,899	$77,899	$77,899
2	Additions to Carrier Property in Service	Exh. RDC-3	$0	$0	$0	$13,009	$0	$0	$0
3	Retirements of Carrier Property in Service	Exh. RDC-3	$0	$0	$0	$0	$0	$0	$0
4	Carrier Property in Service, EOY	Sum Lns. (1 thru 3)	$64,890	$64,890	$64,890	$77,899	$77,899	$77,899	$77,899
5	Accumulated Depreciation of Carrier Property	2/	$44,072	$44,219	$44,366	$44,513	$44,660	$44,807	$44,954
6	Net Carrier Property in Service	Lns. (4 - 5)	$20,817	$20,670	$20,523	$33,386	$33,239	$33,092	$32,945
7	Net AFUDC	3/	$1,698	$1,724	$1,751	$1,777	$1,803	$1,830	$1,856
8	Working Capital	Exh. RDC-4	$1,089	$954	$818	$682	$546	$448	$1,120
9	Accumulated Deferred Income Taxes	4/	$4,952	$4,962	$4,973	$4,983	$4,994	$5,004	$5,015
10	Month-End Rate Base	Lns. (6 + 7 + 8 - 9)	$18,653	$18,386	$18,119	$30,862	$30,595	$30,366	$30,906
11	13-Month Avg. Rate Base for Historical Test-Year	Average Ln. 10							$22,422
	Pro Forma Adjustments to Rate Base								
12	Annualize Sep. 2025 Property Addition	5/	$13,009	$13,009	$13,009	$0	$0	$0	$0
13	Synchronization Adjustment - Deprec.	6/	($45)	($45)	($45)	$0	$0	$0	$0
14	Synchronization Adjustment - Amort. AFUDC	7/	($1)	($1)	($1)	$0	$0	$0	$0
15	Net Pro Forma Adjustment to Rate Base	Sum Lns. (12 thru 14)	$12,962	$12,962	$12,962	$0	$0	$0	$0
16	Month-End Rate Base - After Net Pro Forma Adj.	Lns. (10 + 15)	$31,615	$31,349	$31,082	$30,862	$30,595	$30,366	$30,906
13	13-Month Avg. Rate Base for Normalized Test-Year	Average Ln. 16							$\boxed{\$31,396}$

1/ Amounts per Schedule 9, year-end 2024 column.
2/ 2025 activity reported on Schedule 9, Ln. 2 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
3/ 2025 activity reported on Schedule 9, Ln. 4 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
4/ 2025 activity reported on Schedule 9, Ln. 6 distributed uniformly to each month consistent with the 2024 Oliktok Settlement Agreement.
5/ Reflects Sep. 2025 property addition (see Ln. 2) in service for all of 2025.
6/ Reflects incremental depreciation expense assuming Sep. 2025 property addition in service for all of 2025. Incremental amount per Schedule 10, Ln. 20.
7/ Reflects incremental AFUDC amortization expense assuming Sep. 2025 property addition in service for all of 2025. Incremental amount per Workpaper 1.2, Ln. 12.

Oliktok Pipeline Company
Carrier Property in Service and Depreciation
($000's)

Line No.	Description	Source	Dec 2022 2/	Dec 2023	Dec 2024	Dec 2025	Normalized Test-Year 3/
1	Carrier Property in Service, BOY	Prior Ln. 5		$64,778	$64,890	$64,890	
2	Additions to Carrier Property in Service	Annual Report		$112	$0	$13,009	
3	Retirements of Carrier Property in Service	Annual Report		$0	$0	$0	
4	Adjustments to Carrier Property in Service	Annual Report		$0	$0	$0	
5	Carrier Property in Service, EOY	Lns. (1 + 2 + 3 + 4)	$64,778	$64,890	$64,890	$77,899	
6	Land, BOY	Prior Ln. 10		$0	$0	$0	
7	Additions of Land	Annual Report		$0	$0	$0	
8	Retirements of Land	Annual Report		$0	$0	$0	
9	Adjustments to Land	Annual Report		$0	$0	$0	
10	Land, EOY	Lns. (6 + 7 + 8 + 9)	$0	$0	$0	$0	
11	Depreciable Carrier Property in Service, EOY	Lns. (5 - 10)	$64,778	$64,890	$64,890	$77,899	
12	Remaining Life (in years)	1/		18	17	16	
13	Composite Depreciation Factor	1.0 / Ln. 12 [2/]		5.5556%	5.8824%	6.2500%	
14	Accumulated Depreciation, BOY	Prior Ln. 18		$40,482	$41,835	$43,191	
15	Depreciation Expense	[Prior Ln. 19 + (Lns. (2 - 7) * 50%)] * Ln. 13		$1,353	$1,356	$1,763	$2,169
16	Depreciation - Retirements	Annual Report		$0	$0	$0	
17	Depreciation - Adjustments	Annual Report		$0	$0	$0	
18	Accumulated Depreciation, EOY	Lns. (14 + 15 + 16 + 17)	$40,482	$41,835	$43,191	$44,954	
19	Net Depreciable Carrier Property in Service, EOY	Lns. (11 - 18)	$24,296	$23,055	$21,699	$32,945	
20	Incremental Dep. Expense Due to Pro Forma Adj.	Prior Ln. 15 - Ln. 15					$407

1/ Remaining life per 2024 Oliktok Settlement Agreement, Exhibit F.
2/ 2022 year-end balances per Workpaper 3.
3/ Reflects an annualized amount of depreciation expense assuming Sep. 2025 property addition in service for entire test year.

Oliktok is not seeking to recover cash working capital requirements in its proposed rates.

Oliktok Pipeline Company
Weighted Cost of Capital and Return on Rate Base
For the Normalized Test-Year
($000's)

Line No.	Description	Source	Normalized Test-Year
1	Weighted Cost of Capital	Lns. (6 + 9)	8.20%
2	Rate Base	Schedule 9.1, Ln. 13	$31,396
3	Total Return on Rate Base	Lns. (1 * 2)	$2,573
4	Debt Capital Structure	Exh. BHF-3	55.34%
5	Cost of Debt	Exh. BHF-3	5.13%
6	Debt Weighted Rate of Return	Lns. (4 * 5)	2.84%
7	Interest Expense	Lns. (2 * 6)	$891
8	Equity Rate of Return	Exh. BHF-3	12.00%
9	Equity Weighted Rate of Return	(1 - Ln. 4) * Ln. 8	5.36%
10	Return on Equity	Lns. (2 * 9)	$1,682

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Oliktok Pipeline Company	(1) ☑ An Original (2) ☐ A Resubmission	02/18/2026	End of: 2025/ Q4

Long-Term Debt

Line No.	Name and Description of Obligation (a)	Nominal Date of Issue (b)	Date of Maturity (c)	TOTAL PAR VALUE In Treasury (d)	TOTAL PAR VALUE Sinking, Other Funds (e)	TOTAL PAR VALUE Pledged as Collateral (f)	TOTAL PAR VALUE Payable within 1 Yr. (acc. 57) (g)	TOTAL PAR VALUE Payable After 1 Yr. (acc. 60) (h)
	MORTGAGE BONDS							
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11	TOTAL for Mortgage Bonds							
	COLLATERAL TRUST BONDS							
12								
13								
14								
15								
16								
17	TOTAL for Collateral Trust Bonds							
	INCOME BONDS							
18								
19								
20								
21	TOTAL for Income Bonds							
	MISCELLANEOUS OBLIGATIONS							
22								
23								
24								

Long-Term Debt

Line No.	Name and Description of Obligation (a)	Nominal Date of Issue (b)	Date of Maturity (c)	TOTAL PAR VALUE In Treasury (d)	TOTAL PAR VALUE Sinking, Other Funds (e)	TOTAL PAR VALUE Pledged as Collateral (f)	TOTAL PAR VALUE Payable within 1 Yr. (acc. 57) (g)	TOTAL PAR VALUE Payable After 1 Yr. (acc. 60) (h)
25								
26								
27								
28								
29								
30	TOTAL for Miscellaneous Obligations							
	NONNEGOTIABLE DEBT TO AFFILIATED CO.							
31								
32								
33								
34								
35								
36								
37								
38								
39								
40	TOTAL for Nonnegotiable Debt to Affil. Co.							
41	GRAND TOTAL (Lines 11, 17, 21, 30 and 40)							

Long-Term Debt

Line No.	INTR.PROV Rate Per Annum (in percent) (i)	INTR.PROV Dates Due (j)	Amount of Interest Accrued During Year Charged to Income (in dollars) (k)	Amount of Int. Charged to Construction or Other Investment Account (in dollars) (l)	Amount of Interest Paid During Year (in dollars) (m)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Long-Term Debt					
Line No.	INTR.PROV Rate Per Annum (in percent) (i)	INTR.PROV Dates Due (j)	Amount of Interest Accrued During Year Charged to Income (in dollars) (k)	Amount of Int. Charged to Construction or Other Investment Account (in dollars) (l)	Amount of Interest Paid During Year (in dollars) (m)
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					

Oliktok is sponsoring the testimony of:

- Raj D. Choudhury
- Dr. Bruce H. Fairchild
- Erik G. Wetmore

Oliktok is not seeking to collect in its proposed rates money to cover costs to dismantle or remove a pipeline facility or restore a right-of-way.

Oliktok is not seeking to collect in its proposed rates money to cover costs to dismantle or remove a pipeline facility or restore a right-of-way. Thus, no dismantlement costs are included in the schedule submitted in accordance with Section 275(a)(5).

Line No.	Description	Source	2022	2023	2024	2025
1	Equity Ratio	Dr. Fairchild		42.06%	43.82%	44.66%
2	Debt Ratio	1.0 - Ln. 1		57.94%	56.18%	55.34%
3	Rate of Return on Equity	Dr. Fairchild		13.61%	13.03%	12.00%
4	Rate of Return on Debt	Dr. Fairchild		4.86%	5.02%	5.13%
5	CWIP Additions	Annual Report		$499	$2,718	$9,625
6	CWIP Retirements	Annual Report		$0	$0	$0
7	CWIP Adjustments and Transfers	Annual Report		($112)	$326	($13,255)
8	CWIP Balance	Lns. (5+6+7+Prior 8) 1/	$370	$757	$3,801	$171
9	Average CWIP	Average Ln. 8		$563	$2,279	$1,986
10	Additions to Carrier Property in Service	Schedule 10, Ln. 2		$112	$0	$13,009
11	In Service Ratio	Lns. (10 / (5 + Prior 8))		12.88%	0.00%	96.89%
12	Additions to Equity AFUDC Base	Lns. ((1 * 9 + Prior 14) * 3)		$33	$135	$127
13	Equity AFUDC Additions to Rate Base	Lns. (11 * (12 + Prior 14))		$5	$0	$287
14	Equity AFUDC Base	Lns. (Prior 14 + 12 - 13) 2/	$7	$35	$170	$9
15	Additions to IDC Base	Lns. ((2 * 9 + Prior 17) * 4)		$16	$65	$61
16	IDC Additions to Rate Base	Lns. (11 * (15 + Prior 17))		$3	$0	$138
17	IDC Base	Lns. (Prior 17 + 15 - 16) 3/	$3	$17	$82	$4

1/ 2022 amount per Annual Report.
2/ 2022 amount based on Workpaper 3, Ln. 4.
3/ 2022 amount based on Workpaper 3, Ln. 5.

Oliktok Pipeline Company
Amortization of AFUDC
($000's)

Exhibit EGW-2
Workpaper 1.2

Line No.	Description	Source	Dec 2022 1/	Dec 2023	Dec 2024	Dec 2025	Normalized Test-Year 2/
1	Amortization Factor	Schedule 10, Ln. 13		5.5556%	5.8824%	6.2500%	
2	Net Equity AFUDC - BOY	Prior Ln. 5		$1,141	$1,083	$1,019	
3	Equity AFUDC Transfers to Rate Base	Workpaper 1.1, Ln. 13		$5	$0	$287	
4	Equity AFUDC Amortization	Lns. (1 * (2 + 3 * 50%))		$64	$64	$73	$82
5	Net Equity AFUDC - EOY	Lns. (2 + 3 - 4)	$1,141	$1,083	$1,019	$1,234	
6	Net Debt AFUDC - BOY	Prior Ln. 9		$584	$554	$521	
7	Debt AFUDC Transfers to Rate Base	Workpaper 1.1, Ln. 16		$3	$0	$138	
8	Debt AFUDC Amortization	Lns. (1 * (6 + 7 * 50%))		$32	$33	$37	$41
9	Net Debt AFUDC - EOY	Lns. (6 + 7 - 8)	$584	$554	$521	$622	
10	Total AFUDC Amortization	Lns. (4 + 8)		$96	$96	$110	$123
11	Net AFUDC - EOY	Lns. (5 + 9)	$1,725	$1,636	$1,540	$1,856	
12	Incremental Amort. Expense Due to Pro Forma Adj.	Prior Ln. 10 - Ln. 10					$13

1/ 2022 amounts per Workpaper 3.
2/ Reflects an annualized amount of amortization expense assuming Sep. 2025 property addition in service for entire test year.

Oliktok Pipeline Company
Accumulated Deferred Income Taxes ("ADIT")
($000's)

Line No.	Description	Source	Dec 2022 1/	Dec 2023	Dec 2024	Dec 2025
1	Regulatory Depreciation Incl. Amort. of Debt AFUDC	Schedule 10, Ln. 15 + Workpaper 1.2, Ln. 8		$1,385	$1,389	$1,800
2	State Tax Depreciation	Workpaper 2.3, Ln. 18		$1,816	$1,629	$2,186
3	State Tax Timing Differences	Lns. (2 - 1)		$431	$241	$386
4	State Income Tax Rate	AK Stat.		9.40%	9.40%	9.40%
5	State Tax Effect	Lns. (3 * 4)		$40	$23	$36
6	State ADIT Balance	Ln. 5 + Prior Ln. 6	$1,396	$1,436	$1,459	$1,495
7	Depreciation Incl. Amort. of Debt AFUDC	Ln. 1		$1,385	$1,389	$1,800
8	Depreciation of TEFRA Adjustment	Workpaper 2.2, Ln. 3		$5	$5	$5
9	Regulatory Depreciation after TEFRA Adjustment	Lns. (7 - 8)		$1,380	$1,383	$1,794
10	Federal Tax Depreciation	Workpaper 2.3, Ln. 9		$1,910	$1,876	$2,410
11	Tax Effect of State Timing Differences	Ln. 5		$40	$23	$36
12	Total Federal Tax Deductions	Lns. (10 - 11)		$1,870	$1,853	$2,373
13	Federal Tax Timing Differences	Lns. (12 - 9)		$490	$470	$579
14	Federal Income Tax Rate	IRC		21.00%	21.00%	21.00%
15	Federal Tax Effect	Lns. (13 * 14)		$103	$99	$122
16	Excess Tax Reserve Adjustment	Cum. Ln 13 * Change Ln 14		$0	$0	$0
17	Composite Depreciation Factor	Schedule 10, Ln. 13		5.5556%	5.8824%	6.2500%
18	Amortization of Excess Tax Reserve	Lns. ((Prior 19 + (16 / 2.0)) * 17)		$32	$32	$32
19	Net Excess Tax Reserve Balance (FAS 96/109)	Prior Ln. 19 + Ln. 16 - Ln. 18	$572	$540	$508	$477
20	Federal ADIT Balance	Prior Ln. 20 + Ln. 15 - Ln. 18	$3,292	$3,363	$3,430	$3,520
21	Total State and Federal ADIT Balances	Lns. (6 + 20)	$4,687	$4,799	$4,888	$5,015

1/ 2014 amounts per Workpaper 3.

Oliktok Pipeline Company
TEFRA Adjustment to ADIT
($000's)

Line No.	Description	Source	Dec 2022 1/	Dec 2023	Dec 2024	Dec 2025
1	TEFRA Adjustment Balance (BOY)	Prior Ln. 4		$95	$89	$84
2	Amortization Factor	Schedule 10, Ln. 13		5.5556%	5.8824%	6.2500%
3	Amortization of TEFRA Adjustment	Lns. (1 * 2)		$5	$5	$5
4	TEFRA Adjustment Balance (EOY)	Lns. (1 - 3)	$95	$89	$84	$79

1/ 2022 amounts per Workpaper 3.

Oliktok Pipeline Company
Tax Depreciation
($000's)

Exhibit EGW-2
Workpaper 2.3

Line No.	Description	Source	Dec 2023	Dec 2024	Dec 2025
	Federal Tax Depreciation				
1	Carrier Property Additions (Excluding Land)	Schedule 10, Ln. (2 - 7)	$112	$0	$13,009
2	Debt AFUDC Additions	Workpaper 1.2, Ln. 7	$3	$0	$138
3	Tax Basis for Depreciation	Lns (1 + 2)	$114	$0	$13,147
4	Federal Tax Depreciation Factors	IRC	5.00000%	9.50000%	8.55000%
5	Federal Tax Depreciation Pre-2023	1/	$1,905	$1,865	$1,742
6	Federal Tax Depreciation 2023	2023 Tax Basis * Ln. 4	$6	$11	$10
7	Federal Tax Depreciation 2024	2024 Tax Basis * Ln. 4		$0	$0
8	Federal Tax Depreciation 2025	2025 Tax Basis * Ln. 4			$657
9	Total Federal Tax Depreciation	Sum Lns. (5 to 8)	$1,910	$1,876	$2,410
	State Tax Depreciation				
10	Carrier Property Additions (Excluding Land)	Schedule 10, Ln. (2 - 7)	$112	$0	$13,009
11	Debt AFUDC Additions	Workpaper 1.2, Ln. 7	$3	$0	$138
12	Tax Basis for Depreciation	Lns (10 + 11)	$114	$0	$13,147
13	State Tax Depreciation Factors	AK Stat.	5.71430%	10.77550%	9.82470%
14	State Tax Depreciation Pre-2023	2/	$1,810	$1,617	$1,423
15	State Tax Depreciation 2023	2023 Tax Basis * Ln. 13	$7	$12	$11
16	State Tax Depreciation 2024	2024 Tax Basis * Ln. 13		$0	$0
17	State Tax Depreciation 2025	2025 Tax Basis * Ln. 13			$751
18	Total State Tax Depreciation	Sum Lns. (14 to 17)	$1,816	$1,629	$2,186

1/ Per 2024 Oliktok Settlement Agreement, Exhibit C.
2/ Per 2024 Oliktok Settlement Agreement, Exhibit B.

Oliktok Pipeline Company
Starting Balances per 2024 Oliktok Settlement Agreement
As of December 31, 2022
($000's)

Line No.	Description	Source	Amount
1	Carrier Property in Service	2024 Oliktok Settlement Agreement, Section II-6	$64,778
2	Land	2024 Oliktok Settlement Agreement, Section II-6	$0
3	Accumulated Depreciation	2024 Oliktok Settlement Agreement, Section II-5	$40,482
4	Equity AFUDC Base	2024 Oliktok Settlement Agreement, Section II-8	$7
5	IDC Base	2024 Oliktok Settlement Agreement, Section II-7	$3
6	Net Equity AFUDC - EOY	2024 Oliktok Settlement Agreement, Section II-8	$1,141
7	Net Debt AFUDC - EOY	2024 Oliktok Settlement Agreement, Section II-7	$584
8	State ADIT Balance	2024 Oliktok Settlement Agreement, Section II-13	$1,396
9	Amortization Basis for FASB 96/109 Adjustment	2024 Oliktok Settlement Agreement, Section II-13	$572
10	Federal ADIT Balance	2024 Oliktok Settlement Agreement, Section II-13	$3,292
11	TEFRA Adjustment Balance (EOY)	2024 Oliktok Settlement Agreement, Section II-13	$95

Exhibit EGW-3

Line No. (a)	Description (b)	Source (c)	Projected Revenues Without Rate Change (d)	Projected Revenues With Rate Change (e)
1	GHP Deliveries (thousand Mcf)	Choudhury Testimony	0	0
2	GSP Deliveries (thousand Mcf)	Choudhury Testimony	4,536	4,536
3	KRU Deliveries (thousand Mcf)	Choudhury Testimony	3,482	3,482
4	Tariff Rate - GHP ($ per Mcf)	Exhibit EGW-2, Schedule 4	$0.346	$0.914
5	Tariff Rate - GSP ($ per Mcf)	Exhibit EGW-2, Schedule 4	$0.555	$1.464
6	Tariff Rate - KRU ($ per Mcf)	Exhibit EGW-2, Schedule 4	$0.580	$1.528
7	Projected Revenues - GHP ($000's)	Lns. (1 * 4)	$0	$0
8	Projected Revenues - GSP ($000's)	Lns. (2 * 5)	$2,517	$6,640
9	Projected Revenues - KRU ($000's)	Lns. (3 * 6)	$2,020	$5,320
10	Projected Revenues - Total Intrastate ($000's)	Sum Lns. (7 thru 9)	$4,537	$11,960