COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC., FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF NEW TARIFFS; 3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 4) ALL OTHER REQUIRED APPROVALS AND RELIEF.	)))))))	CASE NO. 2024-00354

REBUTTAL TESTIMONY OF

JAMES J. MCCLAY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 9, 2025

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ATTACHMENT:

Attachment JJM-Rebuttal-1 Hedging Analysis

I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James J. McClay, III, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director of Natural Gas Trading for Progress Energy Carolinas a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. ARE YOU THE SAME JAMES J. MCCLAY THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the recommendations made by Mr. Lane Kollen on behalf of the Kentucky Attorney General (KYAG) related to the Company's proposals for: 1) a comprehensive power hedging program designed to mitigate market volatility for customers and recovered through the Fuel Adjustment Clause (FAC); 2) flexibility to manage the Company's natural gas position through the sales of excess natural gas unable to be burned through commodity sales and to have the proceeds recovered through the Profit Sharing Mechanism (PSM); and 3) recovery of Capacity Performance (CP) insurance premium costs and proceeds through the PSM should the Company purchase a CP insurance policy.

II. DISCUSSION

Q. PLEASE SUMMARIZE DUKE ENERGY KENTUCKY'S PROPOSAL FOR A COMPREHENSIVE HEDGING PROGRAM IN THIS PROCEEDING?

A. As discussed in my direct testimony, Duke Energy Kentucky is proposing to hedge its power position during forced outages and when the PJM AEP-Dayton (AD) hub market power price is under the projected cost of production.[1]

Q. PLEASE PROVIDE A BRIEF SUMMARY OF MR. KOLLEN'S RECOMMENDATIONS REGARDING THE COMPANY'S HEDGING PLAN PROPOSAL.

A. Mr. Kollen recommends that the Commission deny Duke Energy Kentucky's hedging program request and instead direct the Company to initiate a new proceeding to consider the scope and long-term cost effectiveness of the proposed comprehensive hedging program.[2]

Q. PLEASE RESPOND TO MR. KOLLEN'S RECOMMENDATIONS.

A. Duke Energy Kentucky maintains that its hedging proposal is reasonable, in the best interests of customers, and should be approved. Through its active participation in the PJM and MISO Energy markets, the Company has witnessed significant market price volatility inherent in organized energy markets. My team has valuable experience in managing price risk through the mature hedging programs managed in other jurisdictions and in hedging the scheduled outages for Duke Energy Kentucky since 2007. The proposed program's purpose is to provide a reasonable and prudent approach to mitigate price volatility in uncertain energy markets for

[1] Direct Testimony of James J. McClay, p. 5 (McClay Direct).
[2] Direct Testimony of Lane Kollen, p. 9 (Kollen Direct).

the benefit of Duke Energy Kentucky's customers. The Company's risk mitigation experience developed from hedging scheduled outages will be applied to managing forced outages and economic shutdowns of its owned generation units for the benefit of its customers.

Q. MR. KOLLEN CLAIMS THE COMPANY DID NOT PROVIDE A DETAILED DESCRIPTION OF THE COMPANY'S PROPOSED NEW COMPREHENSIVE HEDGING PROGRAM IN ITS APPLICATION. IS HIS ASSERTION CORRECT?

A. No, as I explain in my direct testimony, the new comprehensive hedging program builds on the existing hedging program including the instruments and strategies for scheduled outages successfully employed by the Company since its first Back-up Power Supply Plan in 2007. This strategy that the Company has employed to hedge scheduled outages over the past 18 years will be extended and applied to the new comprehensive hedging program.

Q. WHAT HEDGING TOOLS DOES DUKE ENERGY KENTUCKY PLAN TO USE?

A. Duke Energy Kentucky has used, for many years, fixed-priced financial hedging instruments for scheduled outages. These are power financial swap and future contract products listed on Intercontinental Exchange (ICE) or through the bilateral over the counter (OTC) broker market. The Company plans to use these same tools for its proposed comprehensive hedging program. The ICE is a well-established global electronic marketplace for trading energy-related products. Among other product types, ICE offers trading for energy at fixed forward prices. The contract terms (such as hours of the day covered, the index price, credit, and liquidated damages provisions) are clearly defined, to enable trading in standardized products.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S STATEMENTS IN RELATION TO THE COSTS TO PURCHASE HEDGING PRODUCTS?

A. No. While there are transaction costs to purchase hedging products on ICE, the OTC market, or other trading platforms, these are standardized transaction cost paid by every market participant at same rates, similar to administration fees charged by PJM for RTO transactions. Mr. Kollen's argument that a seller will price call options at "an expected cost greater than if the Company incurred market prices without purchasing hedging products"[3] is not valid and is irrelevant to the Company's proposal because as I specifically stated in my direct testimony, the Company will continue to use financial swap and future contract products listed on ICE or through the bilateral OTC broker market.[4] These are not call options as described by Mr. Kollen. In fact, in preparation for past Back-up Power Supply Plan filings, the Company solicited quotes, on multiple occasions, for various types of call options and reached the same conclusion as Mr. Kollen that call options, by themselves, are not economic hedging tools.

[3] Kollen Direct, p. 57, lines 18-19.
[4] McClay Direct, p. 6, lines 4-6.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S ARGUMENT THAT THE COMPANY DIDN'T PROVIDE "ECONOMIC AND/OR OTHER ANALYTICAL STUDIES THAT COMPARE OUTCOMES WITH AND WITHOUT THE PROPOSED COMPREHENSIVE HEDGING PROGRAM"?

A. The Company has a long history of hedging scheduled outages that could be used to help illustrate the benefits to customers. In the past 18 years, from 2007 through 2024, the Company purchased forward hedges for East Bend's scheduled outages days or months ahead of time, paid the then market prevailing price and settled against hourly PJM AEP-Dayton Hub LMPs while the unit was not available. Over this period, the net result, after all transaction costs including commissions and ICE fees, was a net gain or savings to customers of $2,882,681. There is a fairly wide range of monthly hedging profit/loss from a gain of $3,596,853 in October 2021 to a loss of $3,934,362 in December the same year. Annual gains and losses were less volatile, between a gain of $2,981,512 in 2018 and a loss of $1,280,376 in 2009. See Attachment JJM-Rebuttal-1 for more details. The goal of a hedging program was not to make a profit, but rather to mitigate customers' exposure to market price risk and smooth out purchased power cost when the Company's owned generation units are not available, either due to outages or from an economic perspective. The gains and losses from the hedges help to provide stability in customers' monthly bills.

Q. PLEASE EXPLAIN WHY A COMPREHENSIVE HEDGING PLAN IS REASONABLE, NECESSARY, AND IN CUSTOMERS' BEST INTERESTS?

A. A more comprehensive hedging plan is a proactive measure to mitigate exposure to volatile spot energy prices and improve price certainty for customers. The proposed hedging plan is essential for maintaining price stability, protecting customers from market price volatility, and helping mitigate overall electricity costs.

Economically hedging customer market energy price exposure, when energy market prices are lower than running the plant or during extended forced outages is a common-sense financial win for the customer and reduces plant operations risk potentially resulting in lower O&M. Despite Mr. Kollen's inaccurate representation of the additional risk through hedging, the Company considers a comprehensive hedging program that mitigates purchased power costs during forced outages and economic unit shutdowns to be in customers' best interest.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD APPROVE THE COMPANY'S HEDGING PROPOSAL NOW?

A. Duke Energy Kentucky considers a comprehensive hedging program to be an important part of prudently managing the risk volatility in future purchased power costs which benefits customers.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR FLEXIBILIY IN MANAGING ITS NATURAL GAS PROCUREMENT FOR FUEL.

A. Duke Energy Kentucky is requesting the ability to sell surplus gas purchased but unable to be burned through commodity sales and to have the net proceeds, (difference between purchase price and sale price) positive or negative, recovered through the PSM. The Company requests the ability to manage its daily gas position because it is both good utility practice and a normal part of managing delivered natural gas procured for electric generation employed by Duke Energy Corp. in all its other regulated utility jurisdictions.

Duke Energy Kentucky's current methodology of parking unused gas on the TETCO pipeline is a short-term solution and assumes the pipeline is going to allow this behavior indefinitely. As natural gas consumption for electric generation has increased, the Company has experienced a corresponding decrease in operational flexibility on the natural gas pipelines it manages supply. Duke Energy Kentucky knows that it is unreasonable to assume that TETCO will in fact allow this behavior to continue indefinitely and considers its proposal to be in customers' best interest both now and in the future.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF MR. KOLLEN'S RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSAL FOR FLEXIBLITY IN MANAGING ITS NATURAL GAS FUEL PROCUREMENT.

A. Mr. Kollen recommends that the Commission deny Duke Energy Kentucky's request for approval of its proposed gas management program and the refund or recovery of gains or losses through the FAC.[5]

Q. PLEASE RESPOND TO MR. KOLLEN'S RECOMMENDATIONS.

A. Mr. Kollen's recommendation appears to be based on a misconception that TECTO natural gas pipeline operations will continue to allow the Company unlimited flexibility in managing its physical natural gas supply in perpetuity. As previously discussed in my testimony, the Company is continuing to see a decrease in pipeline operational flexibility and knows that it is unreasonable to assume that gas pipelines, including TECTO will continue to indefinitely allow unlimited flexibility.

Q. PLEASE EXPLAIN WHY THIS FLEXIBILTIY IN MANAGING DUKE ENERGY KENTUCKY'S NATURAL GAS POSITION IS REASONABLE, NECESSARY, AND IN CUSTOMERS' BEST INTERESTS?

A. To avoid unnecessary customer fuel expense, Duke Energy Kentucky does not contract for firm transportation for the Woodsdale CT units. Instead, all of the Company's natural gas supply is purchased as firm delivered supply from third-party suppliers where the Company must take delivery regardless of intraday PJM

[5] Kollen Direct, p. 9, lines 11-13.

dispatch changes. The flexibility to sell excess natural gas is a valuable tool used by the industry to help balance supply and demand changes and ultimately customer costs. In some cases, to work around dispatch uncertainty, Duke Energy Kentucky will wait and procure natural gas in the intraday market once the units are dispatched to avoid over purchasing natural gas in the day ahead market which would result in an accumulating pipeline imbalance. A key constraint when looking to burn imbalanced natural gas off the pipeline is that it cannot be burned when an Operational Flow Order (OFO) has been issued by the pipeline. Typically, this happens during periods of constrained pipeline operations which often coincides higher demand and increasing natural gas prices. Instead, Duke Energy Kentucky must purchase new third-party delivered supply at the then current market price. When the OFO is canceled, it usually coincides with a lower natural gas priced market due to lower demand and the pipeline dictates how much imbalance natural gas can then be burned in a given day. The pipeline requires Duke Energy Kentucky to burn its higher priced imbalance natural gas rather than taking advantage of lower market prices.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD APPROVE THE COMPANY'S GAS MANAGEMENT PROPOSAL NOW?

A. The current natural gas management approach puts the Company in the position where it must rely solely on TETCO Pipeline's operational flexibility to park large amounts of unused natural gas indiscriminately on their system. Duke Energy Kentucky recognizes that pipelines are becoming less flexible in day-to-day operations as evidenced by the increasing number of OFO's and is asking for the ability when it makes economic sense to sell natural gas, so customers may have the opportunity to benefit from the Company's optimization of its natural gas position.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL REGARDING CAPACITY PERFORMANCE INSURANCE PREMIUMS IN THIS PROCEEDING.

A. Duke Energy Kentucky is proposing that in the event it decides to purchase Capacity Performance (CP) insurance, CP insurance premium costs and proceeds be included in the PSM.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF MR. KOLLEN'S RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSAL.

A. Mr. Kollen recommends that the Commission deny Duke Energy Kentucky's request for approval to purchase CP insurance and recover the expense through the PSM.

Q. PLEASE RESPOND TO MR. KOLLEN'S RECOMMENDATIONS.

A. The Company has a relatively concentrated portfolio where one generation asset East Bend unit 2 (600MW ICAP) stands for more than 50% of the portfolio capacity. If this unit is not available during CP events, the rest of the Duke Energy Kentucky generation fleet (Woodsdale CT1-6, total approximately 476MW ICAP) will not be able to offset East Bend's non-performance. Purchasing a CP insurance policy may help mitigate a potential catastrophic cost to customers, should East Bend be unavailable during a PJM CP event. The Company is not pursuing coverage for the six Woodsdale CT units because these units have adequate risk diversification amongst themselves where one unit's non-performance or underperformance could be offset by potential overperformance by the other five units. Under the current PSM sharing mechanism, customers bear 90 percent of the benefit and risk of CP impacts (credits and costs). A CP insurance product would provide customers with proportional coverage for that risk. Therefore, it is appropriate for the mitigation costs and benefits provided to customers by a CP insurance product be included in the PSM.

Q. PLEASE EXPLAIN WHY RECOVERY OF CP INSURANCE PREMIUM COSTS ARE REASONABLE, NECESSARY, AND IN CUSTOMERS' BEST INTERESTS?

A. As discussed in my direct testimony "PJM capacity prices significantly increased in the most recent BRA and are expected to continue to rise. The stop loss, or the maximum that an entity can be charged for a CP penalty is tied to the auction clearing price. Therefore, the higher the auction clearing price, the higher stop loss, and thus the higher the potential CP penalty."[6] In July 2024, PJM base residual auction (BRA) for Delivery Year 2025/2026 cleared at $269.92/MW-Day. The third incremental auction (3rd IA) for the same delivery year cleared at $323.90/MW-day recently on March 11, 2025. This translates to higher than historical average performance penalties in case of CP events. In February 2025, PJM reviewed their proposal with stakeholders to implement a price cap ($325/MW-Day) and floor ($175/MW-Day) for the 26/27 and 27/28 BRAs, as a result of a settlement with the State of Pennsylvania who submitted a Section 206

[6] McClay Direct, p. 19.

complaint at FERC that asked PJM to institute a price cap on capacity prices. It is expected that this proposal will be approved by FERC. This new development indicates that PJM capacity prices likely will stay elevated at least in the near future.

The Commission previously approved a modification to the Rider PSM in Case No. 2017-00321 to include both capacity performance charges and bonus payments as part of the PSM sharing mechanism where customers receive 90 percent of the net benefits/costs related to capacity performance.[7] The Commission's Order in that case, found that the Company's proposal to change to the 90/10 sharing, even factoring in the capacity performance risks, was reasonable. Since that time, customers have clearly benefited from this additional revenue sharing percentage since that case, in light of the additional risks. The Company's proposal is simply to provide a hedge against the potential risk of those costs through insurance. It would be unreasonable to now say customers only get benefits and no risks.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S STATEMENT THAT "THE COMPANY HAS NOT PERFORMED ANY STUDIES TO 'COMPARE OUTCOMES WITH AND WITHOUT CP INSURANCE"?

A. The Company's review primarily focused on comparing potential CP costs in the Fixed Resource Requirement (FRR) versus Reliability Pricing Model (RPM) constructs. In summary the Company determined that RPM has higher CP risk cost when capacity price is under $300/MW-day and FRR has higher cost with capacity

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[7] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental compliance Plan and Surcharge Mechanism; 3) Approval of new tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief,* Case No. 2017-00321, Order (Apr. 13, 2018).

price above $300/MW-day. As mentioned previously, PJM plans to institute a price cap ($325/MW-Day) and floor ($175/MW-Day) for the 26/27 and 27/28 BRAs. For Delivery Year 2025/2026, BRA cleared at $269.92/MW-Day and its 3rd IA cleared at $323.90/MW-day. Regardless, the Company considers customers are better off having CP insurance in place if a catastrophic CP event were to occur i.e., a 24 hour or longer CP event occurring at the same time East Bend is unavailable.

Q. WILL THE COMPANY'S CP PROPOSAL CHANGE IF IT MOVES TO RPM?

A. No. The Company's analysis indicates there's no clear winner for CP risk between RPM and FRR. As I state in my direct testimony "it is in customers best interest for the Company to have the ability to consider the purchase of insurance regardless of whether it is in FRR or RPM."[8]

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD APPROVE THE COMPANY'S PROPOSAL NOW?

A. As I previously discussed, the stop loss, or the maximum that an entity can be charged for a CP penalty, is tied to the BRA auction clearing price. This is true regardless of whether the Company is an FRR or RPM participant. Given that PJM capacity prices in the BRA have risen significantly and are likely to continue to increase the Company expects to continue evaluating the potential purchase of CP insurance to mitigate the increased customer penalty risk should a CP event occur. Since CP insurance is specifically designed to mitigate CP non-performance charges, it is appropriate for the Commission to approve the inclusion of mitigation

[8] McClay Direct, p. 20.

costs and benefits in the PSM with the CP non-performance charges being mitigated. In the event a CP non-performance charge was levied by PJM, the CP insurance payout would offset the charge, reducing the total amount to flow through PSM.[9]

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

[9] *Id*., p. 20.

VERIFICATION

STATE OF NORTH CAROLINA	**)**	
	)	**SS:**
COUNTY OF MECKLENBURG	**)**	

The undersigned, James J. McClay, Managing Director Natural Gas, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

James J. McClay

James J. McClay, Affiant

Subscribed and sworn to before me by James J. McClay on this 27 day of March, 2025.

Sheila Lemoine

NOTARY PUBLIC

SHEILA LEMOINE
Notary Public, North Carolina
Lincoln County
My Commission Expires
July 21, 2029

My Commission Expires:

COMMODITY_CD	Electricity
REVENUE_COMPANY_CD	(All)
RUN_TYPE	(All)
NATIVE_IND	Native
COUNTERPARTY	(Multiple Items)
COST_TYPE_CD	(All)
STRATEGY_NAME	(Multiple Items)
TRADE_TYPE_CD	(All)

	Sum of EXTENDED_AMT	
Year	RISK_MONTH	Total
2007	2007-01-01	$ 4,154.00
2007	2007-02-01	$ (16,257.00)
2007	2007-03-01	$ (43,634.00)
2007	2007-04-01	$ 1,033,537.57
2007	2007-05-01	$ 753,175.93
2007	2007-06-01	$ (254,881.92)
2007	2007-07-01	$ (117,983.00)
2007	2007-08-01	$ 426,364.90
2007	2007-09-01	$ 105,087.45
2007	2007-10-01	$ 22,208.05
2007	2007-11-01	$ (192,287.99)
2007	2007-12-01	$ 11,873.00
2008	2008-01-01	$ (41,985.14)
2008	2008-02-01	$ 2,725.00
2008	2008-03-01	$ 121,345.46
2008	2008-04-01	$ (18,883.32)
2008	2008-05-01	$ 928.12
2008	2008-06-01	$ (315,004.20)
2008	2008-07-01	$ (113,005.30)
2008	2008-08-01	$ (39,929.00)
2008	2008-09-01	$ (45,146.40)
2008	2008-10-01	$ (15,663.06)
2008	2008-11-01	$ (3,006.56)
2008	2008-12-01	$ (3,736.80)
2009	2009-01-01	$ (6,340.80)
2009	2009-02-01	$ (2,760.00)
2009	2009-03-01	$ (3,500.00)
2009	2009-04-01	$ (3,464.88)
2009	2009-05-01	$ (1,293,649.10)
2009	2009-06-01	$ 31,508.80
2009	2009-07-01	$ (4,762.40)
2009	2009-08-01	$ 5,879.80
2009	2009-09-01	$ (4,084.80)
2009	2009-10-01	$ (2,356.80)
2009	2009-11-01	$ (351.90)
2009	2009-12-01	$ 3,505.50
2010	2010-01-01	$ (1,786.88)
2010	2010-02-01	$ 13,519.36

Row Labels	Sum of Total
2007	$ 1,731,356.99
2008	$ (471,361.20)
2009	$ (1,280,376.58)
2010	$ (79,338.46)
2011	$ (66,224.00)
2012	$ (34,652.00)
2013	$ (23,032.40)
2014	$ 72,850.72
2015	$ (117,951.76)
2016	$ (2,469.90)
2017	$ (64,346.94)
2018	$ 2,981,512.49
2019	$ (165,867.38)
2020	$ (1,052,586.45)
2021	$ 1,710,208.68
2022	$ 874,497.47
2023	$ (28,045.53)
2024	$ (1,101,492.06)
Grand Total	**$ 2,882,681.68**

2010	2010-03-01	$	8,843.20
2010	2010-04-01	$	(3,288.12)
2010	2010-05-01	$	(15,095.18)
2010	2010-06-01	$	(62,087.70)
2010	2010-07-01	$	38,534.86
2010	2010-08-01	$	(13,167.14)
2010	2010-09-01	$	(2,097.50)
2010	2010-10-01	$	(37,640.50)
2010	2010-11-01	$	(2,960.40)
2010	2010-12-01	$	(2,112.46)
2011	2011-02-01	$	(2,515.28)
2011	2011-03-01	$	(2,101.82)
2011	2011-04-01	$	(2,189.26)
2011	2011-05-01	$	(2,152.22)
2011	2011-06-01	$	(46,228.86)
2011	2011-07-01	$	(2,134.40)
2011	2011-08-01	$	(15.20)
2011	2011-09-01	$	(2,009.20)
2011	2011-10-01	$	(2,166.96)
2011	2011-11-01	$	(60.00)
2011	2011-12-01	$	(2,000.00)
2011	2012-01-01	$	(2,650.80)
2012	2012-02-01	$	(2,947.80)
2012	2012-03-01	$	(7,397.46)
2012	2012-04-01	$	(2,821.56)
2012	2012-05-01	$	(2,208.00)
2012	2012-06-01	$	(2,400.00)
2012	2012-07-01	$	(2,450.60)
2012	2012-08-01	$	(2,400.00)
2012	2012-09-01	$	(2,401.60)
2012	2012-10-01	$	(2,418.40)
2012	2012-11-01	$	(2,400.00)
2012	2012-12-01	$	(2,400.00)
2012	2013-01-01	$	(2,406.58)
2013	2013-02-01	$	(2,407.84)
2013	2013-03-01	$	(2,400.00)
2013	2013-04-01	$	2,352.71
2013	2013-05-01	$	(3,600.00)
2013	2013-06-01	$	(481.07)
2013	2013-07-01	$	(2,380.00)
2013	2013-08-01	$	(2,184.56)
2013	2013-09-01	$	5,274.56
2013	2013-10-01	$	(2,392.00)
2013	2013-11-01	$	(2,382.00)
2013	2013-12-01	$	(10,070.20)
2013	2014-01-01	$	(2,362.00)
2014	2014-02-01	$	(2,372.00)
2014	2014-03-01	$	43,447.23
2014	2014-04-01	$	161,357.83

2014	2014-05-01	$	(19,627.81)
2014	2014-06-01	$	(75,558.14)
2014	2014-07-01	$	(2,508.68)
2014	2014-08-01	$	(4,298.23)
2014	2014-09-01	$	(11,812.90)
2014	2014-10-01	$	(2,413.64)
2014	2014-11-01	$	(2,400.00)
2014	2014-12-01	$	(7,188.40)
2014	2015-01-01	$	(3,774.54)
2015	2015-02-01	$	(5,308.84)
2015	2015-03-01	$	(15,883.40)
2015	2015-04-01	$	(36,868.27)
2015	2015-05-01	$	(791.78)
2015	2015-06-01	$	(44,322.58)
2015	2015-07-01	$	(2,400.00)
2015	2015-08-01	$	39,399.92
2015	2015-09-01	$	(2,405.12)
2015	2015-10-01	$	(28,093.53)
2015	2015-11-01	$	(12,960.60)
2015	2015-12-01	$	(5,919.56)
2015	2016-01-01	$	(2,398.00)
2016	2016-02-01	$	(2,987.89)
2016	2016-03-01	$	18,023.80
2016	2016-04-01	$	105,455.35
2016	2016-05-01	$	(5,115.04)
2016	2016-06-01	$	(17,814.00)
2016	2016-07-01	$	(59,734.52)
2016	2016-08-01	$	(2,400.00)
2016	2016-09-01	$	(2,400.00)
2016	2016-10-01	$	(2,400.00)
2016	2016-11-01	$	(28,347.60)
2016	2016-12-01	$	(2,350.00)
2016	2017-01-01	$	(2,400.00)
2017	2017-02-01	$	(2,400.00)
2017	2017-03-01	$	(2,400.00)
2017	2017-04-01	$	(3,000.00)
2017	2017-05-01	$	(6,774.73)
2017	2017-06-01	$	(1,030.80)
2017	2017-07-01	$	4,712.93
2017	2017-08-01	$	(3,625.00)
2017	2017-09-01	$	(3,717.45)
2017	2017-10-01	$	(36,621.65)
2017	2017-11-01	$	3,941.62
2017	2017-12-01	$	(8,400.39)
2017	2018-01-01	$	(5,031.47)
2018	2018-02-01	$	(10,135.91)
2018	2018-03-01	$	457,482.79
2018	2018-04-01	$	1,195,205.40
2018	2018-05-01	$	1,415,141.33

2018	2018-06-01	$	(28,158.35)
2018	2018-07-01	$	(3,809.89)
2018	2018-08-01	$	(3,805.48)
2018	2018-09-01	$	(298.69)
2018	2018-10-01	$	(3,750.00)
2018	2018-11-01	$	(28,558.71)
2018	2018-12-01	$	(3,750.00)
2018	2019-01-01	$	(4,050.00)
2019	2019-02-01	$	(14,009.12)
2019	2019-03-01	$	(4,050.00)
2019	2019-04-01	$	(95,095.55)
2019	2019-05-01	$	(9,613.61)
2019	2019-06-01	$	(4,061.00)
2019	2019-07-01	$	(4,101.04)
2019	2019-08-01	$	(4,050.00)
2019	2019-09-01	$	(4,050.00)
2019	2019-10-01	$	(13,176.52)
2019	2019-11-01	$	(5,487.39)
2019	2019-12-01	$	(4,063.15)
2019	2020-01-01	$	(4,110.00)
2020	2020-02-01	$	(4,110.00)
2020	2020-03-01	$	(4,110.00)
2020	2020-04-01	$	(4,110.00)
2020	2020-05-01	$	(29,992.12)
2020	2020-06-01	$	(4,110.00)
2020	2020-07-01	$	(4,110.00)
2020	2020-08-01	$	(4,986.00)
2020	2020-09-01	$	(77,977.58)
2020	2020-10-01	$	(465,584.57)
2020	2020-11-01	$	(445,138.18)
2020	2020-12-01	$	(4,248.00)
2020	2021-01-01	$	(4,110.00)
2021	2021-02-01	$	(4,110.00)
2021	2021-03-01	$	(4,110.00)
2021	2021-04-01	$	57,738.04
2021	2021-05-01	$	13,012.82
2021	2021-06-01	$	(4,110.00)
2021	2021-07-01	$	(4,110.00)
2021	2021-08-01	$	(6,318.50)
2021	2021-09-01	$	215,905.58
2021	2021-10-01	$	3,596,853.01
2021	2021-11-01	$	1,788,978.09
2021	2021-12-01	$	(3,934,362.86)
2021	2022-01-01	$	(5,157.50)
2022	2022-02-01	$	(82,461.50)
2022	2022-03-01	$	(4,200.00)
2022	2022-04-01	$	(149,381.86)
2022	2022-05-01	$	1,133,896.10
2022	2022-06-01	$	(4,455.27)

2022	2022-07-01	$ (4,200.00)
2022	2022-08-01	$ (4,200.00)
2022	2022-09-01	$ (4,200.00)
2022	2022-10-01	$ (4,200.00)
2022	2022-11-01	$ (700.00)
2022	2022-12-01	$ (700.00)
2022	2023-01-01	$ (700.00)
2023	2023-02-01	$ (700.00)
2023	2023-03-01	$ (700.00)
2023	2023-04-01	$ (700.00)
2023	2023-05-01	$ (700.00)
2023	2023-06-01	$ (700.00)
2023	2023-07-01	$ (700.00)
2023	2023-08-01	$ (700.00)
2023	2023-09-01	$ (700.00)
2023	2023-10-01	$ (700.00)
2023	2023-11-01	$ (700.00)
2023	2023-12-01	$ (700.00)
2023	2024-01-01	$ (20,345.53)
2024	2024-02-01	$ (705.00)
2024	2024-03-01	$ (705.00)
2024	2024-04-01	$ (26,804.87)
2024	2024-05-01	$ 13,008.63
2024	2024-06-01	$ (591.00)
2024	2024-07-01	$ (701.50)
2024	2024-08-01	$ (1,636.89)
2024	2024-09-01	$ (232,984.60)
2024	2024-10-01	$ (210,496.95)
2024	2024-11-01	$ (638,429.88)
2024	2024-12-01	$ (705.00)
2024	2025-01-01	$ (740.00)
	Grand Total	$ 2,882,681.68