COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY AND	**)**	
LOUISVILLE GAS AND ELECTRIC COMPANY	**)**	**CASE NO. 2023-00122**
FOR APPROVAL OF SEVEN FOSSIL FUEL-	**)**	
FIRED GENERATING UNIT RETIREMENTS	**)**	

DIRECT TESTIMONY OF
STUART A. WILSON
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 10, 2023

INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Stuart A. Wilson. I am the Director of Energy Planning, Analysis and Forecasting for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I filed testimony and sponsored numerous responses to data requests most recently in Case No. 2022-00402, which is the case concerning the Companies' currently pending application for a number of certificates of public convenience and necessity and approval of a new demand-side management and energy efficiency program plan ("CPCN-DSM case").[1] I provided live testimony before the Commission most recently at the hearing in the Companies' 2021 IRP case,[2] and I have provided other written testimony to the Commission, as well, including in the Companies' 2020 ECR cases.[3]

Q. What is the purpose of your direct testimony?

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[1] *See, e.g., Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Direct Testimony of Stuart A. Wilson (Dec. 15, 2022).

[2] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, July 12, 2022 H.V.T. at 17:43:05-18:10:32 and July 13, 2022 H.V.T. at 08:12:49-12:05:40 (Ky. PSC Oct. 7, 2022).

[3] *See, e.g., Electronic Application of Kentucky Utilities Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020).

A. My testimony presents the Companies' 2023 Fossil Fuel-Fired Electric Generating Unit Retirement Assessment ("Retirement Assessment"), which is attached hereto as Exhibit SB4-1 and which I co-sponsor with Lonnie E. Bellar. The Retirement Assessment summarizes the evidence and analysis in the LG&E 2020 ECR case and the CPCN-DSM case, as well as additional analysis prepared for this filing to demonstrate that the seven fossil fuel-fired electric generating unit retirements the Companies assumed or proposed in the CPCN-DSM case meet the requirements of Senate Bill 4 enacted by the Kentucky General Assembly in March 2023.[4]

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am co-sponsoring Exhibit SB4-1 (the Retirement Assessment) with Mr. Bellar, and I am sponsoring Exhibit SB4-2, which is the collection of workpapers from the Retirement Assessment's quantitative analyses and modeling. Both exhibits were prepared under my supervision and direction.

Exhibit SB4-1 2023 Fossil Fuel-Fired Electric Generating Unit Retirement Assessment

Exhibit SB4-2 Workpapers for the Retirement Assessment

Q. Please describe your and your team's role in the Retirement Assessment.

A. I directed the efforts of members of the Companies' Energy Planning, Analysis and Forecasting group to create the quantitative analysis included in the Retirement Assessment. Those efforts included providing new financial and reliability-related modeling and analysis to compare the continued operation of the Companies' existing resources in compliance with known environmental requirements to retiring the seven

[4] 2023 Ky. Acts 118. The seven units the Companies have assumed or proposed to retire by or in 2028 are E.W. Brown Unit 3, Ghent Unit 2, Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run Unit 12.

fossil fuel-fired electric generating units the Companies have assumed or proposed to retire by or in 2028 and replacing them with the resources proposed in the CPCN-DSM case. The analysis presented in the Retirement Assessment involves new present value of revenue requirements ("PVRR") calculations, reserve margin calculations, and loss-of-load expectation ("LOLE") modeling and results.

Q. Please summarize the results of the Retirement Assessment under your area of responsibility.

A. The Retirement Assessment shows that the proposed retirements and implementing the Companies' proposed CPCN-DSM resource portfolio as compared to incurring the costs to operate the Companies' existing resources result in:

- Present value of revenue requirements ("PVRR") benefits ranging from $344 million to almost $1.3 billion over the study period in the mid coal-to-gas price scenarios;
- Improved system resilience as measured by unit start-up times, ramp rates, and dispatchable range (i.e., the difference between a unit's economic maximum and minimum output levels);
- Maintaining adequate reliability as measured by LOLE and seasonal reserve margins.

Mr. Bellar's testimony explains how the results of the Retirement Assessment meet the requirements of Senate Bill 4 regarding the seven units the Companies assume or propose to retire by the end of 2027.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of May 2023.

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

APPENDIX A

Stuart A. Wilson, CFA
Director, Energy Planning, Analysis and Forecasting
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4993

Previous Positions

Manager, Generation Planning & Analysis	October 2009 – April 2016
Manager, Sales Analysis & Forecasting	May 2008 – October 2009
Supervisor, Sales Analysis & Forecasting	Aug 2006 – April 2008
Economic Analyst	Aug 2000 – July 2006
Compensation Analyst	Aug 1999 – July 2000
Business Analyst	June 1997 – July 1999

Civic Activities

Big Brothers Big Sisters of Kentuckiana, Board of Directors	2017 – Present
Barren Heights Christian Retreat, Board of Directors	2015 – 2021

Professional Memberships

CFA Society of Louisville

Education and Certifications

E.ON Emerging Leaders Program	2004-2006
CFA Charterholder	September 2003
LG&E Energy Leadership Development Program	1997-2002
Master of Business Administration; Indiana University	May 1997
Master of Engineering in Electrical Engineering; University of Louisville	December 1995
Bachelor of Science in Electrical Engineering; University of Louisville	December 1995

2023 Fossil Fuel-Fired Electric Generating Unit Retirement Assessment

PPL companies

Generation Planning & Analysis

May 2023

Exhibit SB4-1

Table of Contents

1 Executive Summary

Following the enactment of Senate Bill 4 by the Kentucky General Assembly in March 2023,[1] Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") performed a series of analyses to determine if the seven coal- or gas-fired units assumed or planned to be retired in the Companies' pending CPCN-DSM proceeding (Kentucky Public Service Commission ("Commission") Case No. 2022-00402) meet the requirements imposed by Senate Bill 4 to obtain Commission approval to retire fossil fuel-fired electric generating units.[2] The analysis presented here demonstrates that the Companies' unit retirement and replacement capacity proposals in the CPCN-DSM case fully satisfy Senate Bill 4's requirements.

Under Senate Bill 4, a utility may receive Commission approval to retire a fossil-fuel fired generating if it rebuts a presumption against such retirement by demonstrating:

- That replacement generating capacity for the retiring unit is dispatchable, will maintain or improve system reliability and resilience, and will maintain sufficient reserve margins;[3]
- That the unit retirement will not harm utility ratepayers;[4]
- That the unit retirement does not result from federal financial incentives or benefits;[5]
- That the unit retirement will result in cost savings for customers after accounting for all known direct and indirect costs of the retirement.[6]

Though the Companies filed their CPCN-DSM application and supporting testimony and analysis prior to Senate Bill 4's enactment, the cost-benefit and reliability analyses the Companies provided in the CPCN-DSM proceeding satisfied all of Senate Bill 4's requirements regarding three coal-fired units (E.W. Brown Unit 3 ("Brown 3"), Mill Creek Unit 2 ("Mill Creek 2"), and Ghent Unit 2 ("Ghent 2")) the Companies propose to retire. In particular, the Companies' analyses specifically demonstrated that such retirements are economical and enhance system reliability when all of the Companies' proposed CPCN-DSM resources are deployed.[7] This analysis confirms the Companies' CPCN-DSM case analysis regarding retiring these units.

In contrast to the proposed retirements of Brown 3, Ghent 2, and Mill Creek 2, the Companies' CPCN-DSM analysis assumed the retirement of Mill Creek Unit 1 ("Mill Creek 1") by 2025 based on the Companies' previous demonstration in LG&E's 2020 ECR case that adding environmental controls to Mill Creek 1 to achieve compliance with the U.S. Environmental Protection Agency's Effluent Limitation Guidelines

[1] After Senate Bill 4's enactment, the Legislative Research Commission compiled it in the Kentucky Acts as 2023 Ky. Acts 118. For ease of reference, the Companies refer to it throughout the text as Senate Bill 4.

[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Attachment to Companies' Response to JI 2-60(a), May 2023 Update to Exhibit SAW-1 (May 4, 2023) (referred to herein as "May 2023 Update to Exhibit SAW-1").

[3] 2023 Ky. Acts 118 § 2(2)(a).

[4] 2023 Ky. Acts 118 § 2(2)(b).

[5] 2023 Ky. Acts 118 § 2(2)(c).

[6] 2023 Ky. Acts 118 § 2(3).

[7] Case No. 2022-00402, May 2023 Update to Exhibit SAW-1 (May 4, 2023).

("ELG") was uneconomical.[8] This analysis shows that the Companies' position in the CPCN-DSM case and analysis in LG&E's 2020 ECR case regarding retiring Mill Creek 1 by 2025 remain valid and that the retirement satisfies Senate Bill 4's requirements.

The Companies' CPCN-DSM analysis further assumed the retirement of three old, small-frame gas-fired combustion turbines (Haefling Units 1-2 ("Haefling 1-2") and Paddy's Run Unit 12 ("Paddy's Run 12")) by 2025 because each would be uneconomical to repair if it experienced a major mechanical issue.[9] Notably, this was a planning assumption based on the Companies' experience with the performance of similar small-frame CTs the Companies have retired due to similar major mechanical issues. The Companies do not plan to retire these units until they fail; but they can reasonably be expected to fail in the short run given their age and service lives. Nonetheless, to ensure the Companies have Commission authority to retire these units when they fail, the Companies demonstrate in this analysis that such retirements meet Senate Bill 4's requirements.

This analysis incorporates the information the Companies have previously provided in LG&E's 2020 ECR case and the CPCN-DSM case regarding the seven retiring fossil fuel-fired units and their proposed replacement resources.[10] It demonstrates that the Companies' customers will not be harmed by these retirements; rather, they will receive benefits in the form of present value revenue requirements ("PVRR") from the Companies' CPCN-DSM proposals ranging from $344 million to almost $1.3 billion in the mid coal-to-gas price scenarios (see Table 8). This analysis also demonstrates that the proposed retirements and replacements will maintain or improve system reliability (see Table 5 and Table 7), improve system resilience (see Table 6), and maintain adequate reserve margins (see Table 7).

Finally, to demonstrate full compliance with all Senate Bill 4 requirements, this analysis notes that the proposed retirements do not result from any federal financial incentive or benefit.

2 Summary of the Unit Retirements and Additional Resources Included in the Companies' 2022 CPCN-DSM Application

The Companies' CPCN-DSM application proposed the retirement of seven fossil fuel-fired electric generating units, and it proposed to add an array of supply-side and demand-side resources to the Companies' resource portfolio to achieve optimal economics and reliability. Because the supporting analysis and documentation for the Companies' CPCN-DSM proposals are already in the record of the CPCN-DSM case and are being incorporated by reference into this proceeding, this analysis does not restate that information at length; rather, a summary of the CPCN-DSM retirements and replacement resources is below for ease of reference.

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[8] *Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

[9] Four similar small-frame CTs (Haefling 3, Cane Run 11, Paddy's Run 11, and Zorn 1) have experienced major mechanical issues and retired in the past 10 years.

[10] Accompanying the filing of this analysis is the Companies Motion to Consolidate, Incorporate by Reference, and Grant Intervention. That Motion requests incorporation of the entire record of Case No. 2020-00061, and this case (Case No. 2023-00122) with and into Case No. 2022-00402. This analysis depends upon the vast amount of data and analysis already supplied in those records; it does not re-present that information here, but it does refer to information in those records as though fully included here.

2.1 Retirements Included in CPCN-DSM Case

As shown in greater detail in Appendix A to this analysis, all seven of the fossil fuel-fired electric generating units the Companies anticipate retiring by 2028 will be at least 50 years old by their proposed retirement dates, are at or near the end of their useful lives, and would require significant investments to continue to operate in compliance with all applicable laws beyond their proposed retirement dates. Table 1 below provides salient information regarding the retiring units.

Table 1: Summary of Unit Retirements Addressed in CPCN-DSM Case

Unit(s)	Fuel	Net Summer/ Winter Capacity (MW)	Dispatchable Summer/ Winter Range (MW)	In-Service Date	Additional Information
Mill Creek 1 ("MC1")	Coal	300/300	Current: 185/185 w/ SCR: 145/145	1972	SCR required today for either Mill Creek 1 or 2 to operate units simultaneously during May-October.[11] Operation beyond 2024 would require ELG retrofits, and operation beyond 2027 would require a cooling tower. SCR required for ozone-season (May-September) operation beginning in 2027 due to Good Neighbor Plan.[12]
Mill Creek 2 ("MC2")	Coal	297/297	Current: 183/183 w/ SCR: 145/145	1974	SCR required today for either Mill Creek 1 or 2 to operate units simultaneously during May-October.[11] SCR required for ozone-season operation beginning in 2027 due to Good Neighbor Plan.
Brown 3 ("BR3")	Coal	412/416	272/276	1971	SCR-equipped but least economical of the Companies' coal units to operate. Major overhaul required in 2027 for reliable operation beyond 2028.
Haefling 1-2 ("HF1-2"); Paddy's Run 12 ("PR12")	Gas	47/55	0/0	1970; 1968	Economical for limited peaking operation. Uneconomical to repair any major mechanical issue. Companies anticipate mechanical failures will require retirement by 2025.[13]
Ghent 2 ("GH2")	Coal	485/486	Current: 260/261 w/ SCR: 256/257	1977	SCR required for ozone-season operation beginning in 2027 due to Good Neighbor Plan.

2.2 Supply-Side and Demand-Side Resources Included in CPCN-DSM Case

The record of the CPCN-DSM case provides a vast array of information concerning the supply- and demand-side resources the Companies considered in the process of arriving at their final proposed supply- and demand-side resource additions. Table 2 below provides a summary of the resource additions the Companies have proposed in the CPCN-DSM case and includes information relevant to Senate Bill 4.

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[11] Per an agreement with the Louisville Air Pollution Control District, the Mill Creek Station is subject to a NO_x limit of 15 tons per day between May and October, which effectively eliminates the ability to operate Mill Creek 1 and Mill Creek 2 simultaneously during these months.

[12] The Companies initially demonstrated the economics of retiring Mill Creek 1 in LG&E's 2020 ECR case. *See* Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

[13] Four similar small-frame CTs (Haefling 3, Cane Run 11, Paddy's Run 11, and Zorn 1) have experienced major mechanical issues and retired in the past 10 years. Such mechanical issues could occur before or after 2025, but the Companies believe it is reasonable for system planning to assume their retirement by 2025.

Two terms used in Table 2 and throughout this analysis require definition:

- **Dispatchable.** Senate Bill 4 does not define "dispatchable," but an industry definition of "dispatchable generation" is, "Generation that can follow dispatch instructions between economic minimum and economic maximum."[14] Note that under this industry definition of "dispatchable generation," a solar facility at midnight and a combustion turbine that is offline are equally not "dispatchable generation" at that moment. Under the same definition, a functioning solar facility in full sun and a combustion turbine that is online and has adequate fuel supply and pressure are equally dispatchable by the entity with the right to adjust their output from economic minimum to maximum. Therefore, a more complete definition of "dispatchable" that explicitly states these implicit concepts is "capable of following dispatch instructions between economic minimum and economic maximum when (i) the generating unit is physically capable of producing electricity and (ii) the unit's power source is available."

- **Dispatchable range.** A unit's dispatchable range is the difference between its economic maximum and its economic minimum output levels in kW or kVA.

[14] PJM Glossary, available at https://www.pjm.com/Glossary#index_D (accessed Apr. 12, 2023); Indiana Utility Regulatory Commission, "2022 Glossary of Electric and Natural Gas Terms and Concepts" at 73, available at https://pubs.naruc.org/pub/DD7DB67E-1866-DAAC-99FB-36526B06C7C6?_gl=1*1qdnvr8*_ga*MTM5OTA2NzQzNi4xNjgxMzIxMTU3*_ga_QLH1N3Q1NF*MTY4MTMyMTE1Ny4xLjEuMTY4MTMyMTE5OS4wLjAuMA (accessed Apr. 12, 2023).

Table 2: Summary of the Companies' Proposed Supply- and Demand-Side Resource Additions in the CPCN-DSM Case

Resource	Input Energy Source	Net Summer/ Winter Capacity (MW)	Dispatchable Summer/ Winter Range (MW)	In-Service Date(s)	Dispatchable?	Electric Generating Capacity?
Mill Creek NGCC (Mill Creek 5, or "MC5")	Gas	621/641	395/380	2027	Yes	Yes
Brown NGCC (Brown 12, or "BR12")	Gas	621/641	395/380	2028	Yes	Yes
Companies-owned solar	Solar	189/0[15]	240/240[16]	2026-2027	Yes[17]	Yes
Brown Battery Energy Storage System (Brown BESS)	Various	125/125	125/125	2026	Yes	No
Dispatchable DSM	N/A	102/89[18]	102/89	2024-2025[19]	Yes	No
Solar PPAs	Solar	678/0[15]	0/0	2024-2027	No	Yes

3 Senate Bill 4's Requirements for Retiring Fossil-Fuel Fired Electric Generating Units and How the Companies' Proposed Unit Retirements and Replacement Resources Meet those Requirements

This section explains how the Companies applied relevant Senate Bill 4 provisions in conducting this analysis. It further demonstrates how the Companies' proposed unit retirements and replacement resources meet all of Senate Bill 4's requirements.

[15] Capacity values reflect 78.6% expected contribution to summer peak capacity and 0% expected contribution to winter peak capacity.

[16] The dispatchable range for the Companies' owned solar assets will be a function of availability of solar irradiance and will vary up to the units' nameplate capacity of 240 MW.

[17] The Companies' owned solar assets will not be dispatchable at all the same times and in all the same conditions as a thermal unit or battery, but the Companies will have full operational control to curtail or re-dispatch these assets when they are able to produce energy.

[18] Values reflect expected contributions in 2028 under normal peak weather conditions.

[19] The in-service dates shown here reflect when the Companies anticipate having at least some participants in each of their new dispatchable DSM programs. *See* Case No. 2022-00402, Direct Testimony of John Bevington, Exhibit JB-1 at 45-52 (Dec. 15, 2022).

3.1 Rebuttable Presumption Against Unit Retirement (Senate Bill 4 Section 2(2))

Section 2(2) of Senate Bill 4 creates a "rebuttable presumption against the retirement of a fossil fuel fired electric generating unit."[20] To address this presumption, the Companies evaluated and compared nine resource portfolios summarized in Table 3 below. The reference case in this analysis is Portfolio 0 ("No Retirements + DSM-EE"), which is the Companies' existing resource portfolio—including all costs associated with operating and maintaining it over the entire analysis period consistent with applicable law—plus the Companies' proposed 2024-2030 Demand-Side Management and Energy Efficiency ("DSM-EE") Program Plan portfolio of DSM-EE programs. This is an appropriate reference portfolio because the Companies have demonstrated that their proposed DSM-EE programs are cost-effective means of adding reliability, which would benefit any supply-side portfolio. Also, adding DSM-EE to all portfolios focuses the analysis on supply-side resource retirements and additions, which is consistent with the focus of Senate Bill 4, and it focuses on the demand that remains to be served *after* accounting for economical DSM-EE. Portfolio 8 is the Companies' full proposed CPCN-DSM resource portfolio in 2028.[21] Each intervening portfolio shows the impact of various unit retirements and resource additions between Portfolio 0 and Portfolio 8, guided by Senate Bill 4's focus on replacing retiring fossil fuel-fired units with dispatchable electric generating capacity. Portfolios 1-6 show incremental unit retirements and additions of resources that are both dispatchable and electric *generating* capacity (NGCC and Companies-owned solar). Portfolio 7 shows the addition of the dispatchable but non-generating Brown BESS. Portfolio 8 completes the CPCN-DSM portfolio by adding non-dispatchable electric generating resources (solar PPAs, including the Rhudes Creek and Ragland PPAs).

[20] 2023 Ky. Acts 118 § 2(2).

[21] The Companies conducted their SERVM modeling using the same load forecast, unit characteristic assumptions, and other relevant assumptions as they used in their SERVM modeling presented in the May 2023 Update to Exhibit SAW-1 and supported by the workpapers provided in Exhibit SAW-2 in the CPCN-DSM case. Additional workpapers supporting the SERVM modeling presented here are included in Exhibit SB4-2 to the Direct Testimony of Stuart A. Wilson filed in this proceeding.

Table 3: Portfolios Evaluated (Incremental Changes to the Prior Portfolio are Highlighted in Blue)

	Portfolio	Description
0	No Retirements; Add DSM	The Companies' existing portfolio, reflecting all investments in environmental controls necessary to maintain continued operation. Rhudes Creek and Ragland solar PPAs are not included. The Companies' 2024-2030 DSM-EE Program Plan portfolio is included.
Fossil retirements and dispatchable electric generating replacements:		
1	Ret MC1-2; Add DSM/MC5	Portfolio 0 above, except Mill Creek 1 is retired by the end of 2024, Mill Creek 2 is retired in 2027, and Mill Creek 5 is commissioned in 2027.
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	Portfolio 1 above, except Brown 3 is retired in 2028, and Brown 12 is commissioned in 2028.
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	Portfolio 2 above, except Paddy's Run 12 and Haefling 1-2 are retired in 2025.
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	Portfolio 3 above, except Ghent 2 is only operable in non-ozone season[22] beginning in 2028.
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	Portfolio 4 above, except Ghent 2 is retired in 2028.
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	Portfolio 5 above, except Mercer Solar and Marion Solar assets are commissioned in 2026 and 2027, respectively.
Add dispatchable non-generating resources:		
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	Portfolio 6 above, except Brown BESS is commissioned in 2026.
Add non-dispatchable electric generating resources:		
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	Portfolio 7 above, except the six solar PPAs (Rhudes Creek, Ragland, and the 637 MW identified in the CPCN) are added from 2024 through 2027.

The Companies evaluated relevant characteristics on an incremental basis to demonstrate each portfolio decision's impact on each characteristic. For each portfolio, this analysis projects costs through 2050, including all stay-open and capital costs necessary to ensure compliance with known, applicable environmental requirements, including ELG and the Good Neighbor Plan. Consistent with the Companies' CPCN-DSM analysis, reliability characteristics such as loss-of-load expectation ("LOLE") and reserve margin are evaluated for 2028.

3.2 Replacement Capacity Requirements (Senate Bill 4 Section 2(2)(a))

Section 2(2)(a) of Senate Bill 4 states the following regarding evidence a utility must present to rebut the presumption against retiring a fossil fuel fired electric generating unit:

[22] Non-ozone season comprises the months from October through April.

(a) The utility will replace the retired electric generating unit with new electric generating capacity that:

1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;

2. Maintains or improves the reliability and resilience of the electric transmission grid; and

3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator[.]

The following subsections address these requirements.

3.2.1 Dispatchability (Senate Bill 4 Section 2(2)(a)(1))

3.2.1.1 The Dispatchability Requirement

Senate Bill 4 requires replacement capacity for a retiring generating unit to be "dispatchable by … the utility."[23] As explained in Section 2.2, because Senate Bill 4 does not define "dispatchable," this analysis defines it to be "capable of following dispatch instructions between economic minimum and economic maximum when (i) the generating unit is physically capable of producing electricity and (ii) the unit's power source is available."

3.2.1.2 The Companies' CPCN-DSM Proposals Meet the Dispatchability Requirement

The Companies' proposed NGCC units and owned solar facilities (not PPAs) are "dispatchable by … the utility" because the Companies will have the physical ability and full rights to control the output of those facilities when they are capable of producing electricity.

In addition, as Table 4 below shows, both the Companies' proposed replacement dispatchable generating capacity (only the proposed NGCCs and Companies-owned solar) and the full CPCN-DSM portfolio will have broader dispatchable ranges than the seven units the Companies propose to retire.

[23] 2023 Ky. Acts 118 § 2(2)(a)(1).

Table 4: Incremental Changes in Total and Dispatchable Capacity (MW)

	Portfolio	Net Summer/Winter Capacity[24]			Dispatchable Summer/Winter Range (Net Max less Net Min)[24]		
		Retired Resource	Proposed Resource	Diff: Proposed less Retired	Retired Resource	Proposed Resource	Diff: Proposed less Retired
0	No Retirements; Add DSM	0/0	0/0	0/0	0/0	0/0	0/0
	Fossil retirements and dispatchable electric generating replacements:						
1	Ret MC1-2; Add DSM/MC5	590/ 590	621/ 641	31/ 51	290/ 290	395/ 380	105/ 90
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	1,002/ 1,006	1,242/ 1,282	240/ 276	562/ 566	790/ 760	228/ 194
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	1,049/ 1,061	1,242/ 1,282	193/ 221	562/ 566	790/ 760	228/ 194
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	1,530/ 1,061	1,242/ 1,282	(288)/ 221	818/ 566	790/ 760	(28)/ 194
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	1,530/ 1,543	1,242/ 1,282	(228)/ (261)	818/ 823	790/ 760	(28)/ (63)
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	1,530/ 1,543	1,431/ 1,282	(99)/ (261)	818/ 823	1,030/ 1,000	212/ 177
	Add dispatchable non-generating resources:						
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	1,530/ 1,543	1,556/ 1,407	26/ (136)	818/ 823	1,155/ 1,125	337/ 302
	Add non-dispatchable electric generating resources:						
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	1,530/ 1,543	2,234/ 1,407	704/ (136)	818/ 823	1,155/ 1,125	337/ 302

Therefore, the proposed retirements and replacements will not just maintain but will actually improve the dispatchability of the Companies' generating fleet, fully satisfying the dispatchability requirement of Senate Bill 4 Section 2(2)(a)(1).

3.2.2 Reliability and Resilience (Senate Bill 4 Section 2(2)(a)(2))

Section 2(2)(a)(2) requires that replacement electric generating capacity "[m]aintain[] or improve[] the reliability and resilience of the electric transmission grid[.]"[25]

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[24] Values for Mill Creek 1-2 and Ghent 2 reflect the expected net capacity and dispatchable ranges after commissioning of environmental controls required for continued operation.

[25] This analysis is based on the focus of Section 2(2)(a)(2) on the reliability and resilience of electric supply, particularly given the statute's definition of "reliability" as "having adequate electric ***generation capacity*** to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand" (emphasis added).

3.2.2.1 The Reliability Requirement

Senate Bill 4 defines "reliability" in Section 1 as "having adequate electric generation capacity to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand[.]" The Companies have long sought to ensure reliable service for their customers by maintaining adequate reserve margins, which is consistent with Senate Bill 4's definition of "reliability."

The Companies have a robust process for establishing reserve margin target ranges in their reserve margin studies, the most recent of which is the 2022 RFP Minimum Reserve Margin Analysis, which is Appendix D to the Companies' 2022 Resource Assessment in the CPCN-DSM case.[26] The Companies establish the low end of their summer and winter minimum reserve margin ranges by determining their economic reserve margin in each season. The reserve margin for the generation portfolio where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin. In the 2022 RFP Minimum Reserve Margin Analysis, the Companies established seasonal minimum reserve margin targets of 17% in the summer and 24% in the winter. In the first two stages of the 2022 Resource Assessment, the Companies developed their economically optimal portfolio for meeting these reserve margin targets and complying with the Good Neighbor Plan.[27]

Another metric the Companies use to evaluate reliability is loss-of-load expectation ("LOLE"), which is typically expressed as the number of loss of load days expected in a ten-year period. It is a widely used reliability metric in the electric industry,[28] and the Companies routinely use it to evaluate the reliability differences of potential resource portfolio additions, including in the CPCN-DSM case.[29] It is also a metric that can show the differing degrees of reliability of portfolios that have the same reserve margins. For example, the 2022 RFP Minimum Reserve Margin Analysis calculated the LOLEs of four different resource portfolios for the Companies that had identical reserve margin values (17.9% summer; 26.0% winter) moderately higher than the Companies' economically optimal minimum reserve margin targets (17% summer; 24% winter).[30] All of the portfolios consisted of the Companies' existing resources without the seven units the Companies assume or propose to retire but with the proposed Mill Creek NGCC (which had 10.3% summer and 17.6% winter reserve margins). Each portfolio then added 480 MW of SCCT capacity, 4-hour BESS capacity, 8-hour BESS capacity, or dispatchable DSM. Therefore, the portfolios all had identical reserve margins, but they had markedly different LOLE values, and therefore reliability, ranging from 3.57 (the SCCT portfolio) to 15.14 (the dispatchable DSM portfolio).[31] In this analysis, the Companies treat an LOLE of 3.57 as consistent with maintaining adequate reliability because this LOLE is aligned with the Companies' minimum reserve margin targets, i.e., any portfolio with a lower LOLE than 3.57 provides more than adequate reliability.

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[26] Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D (May 4, 2023).

[27] *Id*. at Sections 4.4 and 4.5.

[28] *See, e.g.,* The Brattle Group and Astrape Consulting, "Resource Adequacy Requirements: Reliability and Economic Implications," prepared for the Federal Energy Regulatory Commission (FERC) (Sept. 2013), available at https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf (accessed Apr. 12, 2023); North American Electric Reliability Corporation ("NERC"), "2022 Long-Term Reliability Assessment" (Dec. 2022), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf (accessed Apr. 12, 2023); NERC Standard BAL-502-RF-03, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RF-03.pdf.

[29] *See, e.g.,* Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Section 4.6.2 (May 4, 2023).

[30] *Id.* at Appendix D page D-24, Table 15.

[31] *Id.* at Appendix D page D-24, Table 15.

3.2.2.2 How the Companies' CPCN-DSM Proposals Meet the Reliability Requirement

To evaluate the reliability of the Companies' current resource portfolio and show the impacts of the proposed retirements and addition of replacement capacity and other resources, the Companies used the SERVM model to calculate seasonal and total LOLE for the nine portfolios referenced in Table 3.[32] (Table 7 in Section 3.2.3.2 shows that all nine portfolios exceed the Companies' minimum seasonal reserve margin targets.) As Table 5 below shows, the proposed retirements and dispatchable replacement generating capacity will maintain adequate reliability (i.e., LOLE less than 3.57), thereby meeting the requirements of Senate Bill 4 Section 2(2)(a)(2). It further demonstrates that the Companies' full CPCN-DSM portfolio results in summer and full-year reliability improvements compared to the existing resource portfolio.

Table 5: 2028 Reliability Analysis

	Portfolio	**LOLE (days/10 years)**		
		Summer (Jun-Aug)	**Winter (Jan-Feb, Dec)**	**Full Year**
0	No Retirements; Add DSM	0.23	0.21	**0.45**
Fossil retirements and dispatchable electric generating replacements:				
1	Ret MC1-2; Add DSM/MC5	0.23	0.17	**0.41**
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	0.07	0.05	**0.13**
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	0.07	0.08	**0.15**
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	0.80	0.06	**0.92**
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	0.74	0.43	**1.22**
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	0.33	0.42	**0.77**
Add dispatchable non-generating resources:				
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	0.18	0.25	**0.45**
Add non-dispatchable electric generating resources:				
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	0.03	0.25	**0.28**

[32] Fuel assurance is not a separate reliability criterion addressed in this analysis because the forced outage rates included in the SERVM analysis account for credible fuel assurance issues. The Companies' forced outage rate assumptions remain reasonable following the December 2022 load shedding event because Texas Gas Transmission and the Companies have taken and are taking measures to avoid a reoccurrence of such an event.

To test a sensitivity in which the Commission did not approve the Companies' proposed dispatchable DSM programs, the Companies calculated LOLE for Portfolio 8 without dispatchable DSM. The results show that the Companies' proposed CPCN-DSM portfolio still provides excellent reliability without dispatchable DSM: 0.05 summer; 0.34 winter; 0.39 full year. Nonetheless, the Companies support their proposed dispatchable DSM programs for the added cost-effective reliability benefits they provide.

Finally, note that retiring the fossil fuel-fired electric generating units without adding at least the two NGCC units the Companies have proposed would not achieve adequate reliability, and therefore would not satisfy Senate Bill 4's requirements. As shown in the Companies' most recent reserve margin study (presented in the CPCN-DSM case), retiring the seven units at issue and adding only one NGCC unit (the Mill Creek NGCC) would result in a 10.3% summer reserve margin and a 17.6% winter reserve margin, as well as an LOLE of 21.32.[33]

3.2.2.3 The Resilience Requirement

Senate Bill 4 defines "resilience" in Section 1 as "having the ability to quickly and effectively respond to and recover from events that compromise grid reliability[.]" In this analysis, the metrics used to evaluate resilience are generating units' start-up times, ramp rates, and range of dispatchable capacity (i.e., the difference between dispatchable minimum and maximum capacity), as these are the objective, established metrics the Companies can use to determine responsiveness to events affecting load.

3.2.2.4 How the Companies' CPCN-DSM Proposals Meet the Resilience Requirement

As explained in Section 3.2.2.3 above, the appropriate metrics to evaluate resilience for Senate Bill 4 purposes are start-up times, ramp rates, and dispatchable capacity. Table 6 below shows that both of the Companies' proposed NGCC units have faster start-up times and ramp rates than each and every unit the Companies propose to retire. Moreover, the proposed NGCC units, owned solar, and Brown BESS collectively have a broader range of dispatchable capacity (i.e., the difference between dispatchable minimum and maximum capacity) than the combined dispatchable capacity of the retiring units. In short, these units will enhance the Companies' ability to "quickly and effectively respond to and recover from events that compromise grid reliability[.]"

[33] Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D at D-23 – D-24 (May 4, 2023).

Table 6: Comparison of Resilience of Retired and Proposed Supply-Side Resources

	Start-up Times (Hours)[34]	Ramp Rate (MW/min)	Dispatchable Summer/Winter Range (Net Max less Net Min, MW)[35]
Retired Resources:			
Mill Creek 1	11-34	3	145/145
Mill Creek 2	11-34	3	145/145
Ghent 2	18-32	7	256/257
Brown 3	12-20	6	272/276
Haefling 1-2	1	0[36]	0/0
Paddy's Run 12	1	0[36]	0/0
Total			818/823
Proposed Resources:			
Mill Creek 5	1-3	85	395/380
Brown 12	1-3	85	395/380
Owned Solar	Instantaneous	Varies[37]	240/240[38]
Brown BESS	Instantaneous	125	125/125
PPA Solar[39]	N/A	N/A	0/0
Total			1,155/1,125
Net			337/302

In addition, Table 6 shows that the other dispatchable resources the Companies have proposed in the CPCN-DSM proceeding will also provide rapid, rampable energy or demand-reduction when the resources are available, further improving system resilience. Owned solar capacity is also important (though more time- and weather-limited) in this regard.

3.2.3 Reserve Capacity Requirement (Senate Bill 4 Section 2(2)(a)(3))

Section 2(2)(a)(3) requires that replacement electric generating capacity "[m]aintain[] the minimum reserve capacity requirement established by the utility's reliability coordinator[.]"

[34] Values reflect a range of hot start times to cold start times.

[35] Values for Mill Creek 1-2 and Ghent 2 reflect the expected dispatchable ranges after commissioning of environmental controls required for continued operation.

[36] Paddy's Run 12 and Haefling 1-2 are not very effective at following load and would be expected to maintain a stable output level when dispatched to serve load. The Companies assume no ramping capabilities from these units.

[37] The ramp rate for the Companies' owned solar assets will be a function of availability of solar irradiance and will vary up to the units' nameplate capacity of 240 MW.

[38] The Companies' owned solar assets will not be dispatchable at all the same times and in all the same conditions as a thermal unit or battery, but the Companies will have full operational control to curtail or re-dispatch these assets when they are able to produce energy.

[39] The Companies will be contractually obligated to take generation output from the solar PPAs and will be unable to control their dispatch in normal operations.

3.2.3.1 The Reserve Capacity Requirement

The Companies have contracted with the Tennessee Valley Authority ("TVA") to act as the Companies' reliability coordinator since the Companies exited Midwest Independent System Operator ("MISO"), but in that role TVA does not have the obligation or authority to prescribe a reserve capacity requirement for the Companies. Instead, the Companies establish their reserve margins using reserve margin studies that are subject to Commission review in integrated resource plan and CPCN cases, among others.[40] Therefore, the Companies assume that meeting the Companies' seasonal reserve margin targets is a sufficient demonstration of a reasonable reserve of capacity.

3.2.3.2 How the Companies' CPCN-DSM Proposals Meet the Reserve Capacity Requirement

Table 7 below shows that the Companies' proposed replacement resources for the retiring units will exceed the Companies' own minimum reserve margin targets and therefore satisfy the reserve capacity requirement of Senate Bill 4 Section 2(2)(a)(3):

[40] *See, e.g., Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, IRP Vol. III, "2021 IRP Reserve Margin Analysis" (Oct. 19, 2021); Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D (May 4, 2023).

Table 7: 2028 Reserve Margins

	Portfolio	Reserve Margin	
		Summer	Winter
0	No Retirements Add DSM	27.4%	34.7%
Fossil retirements and dispatchable electric generating replacements:			
1	Ret MC1-2; Add DSM/MC5	27.8%	35.4%
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	31.1%	39.1%
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	30.4%	38.2%
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	22.7%	38.2%
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	22.7%	30.2%
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	25.7%	30.2%
Add dispatchable non-generating resources:			
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	27.7%	32.3%
Add non-dispatchable electric generating resources:			
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	38.4%	32.3%

3.3 No Harm to Utility Ratepayers (Senate Bill 4 Section 2(2)(b)))

Senate Bill 4 states in Section 2(2)(b) that part of what a utility must show to overcome the rebuttable presumption against retiring a fossil fuel fired electric generating unit is:

> The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law[.]

3.3.1 Interpreting the No Harm to Utility Ratepayers Requirement

This analysis compares the present value of revenue requirements ("PVRR") of continuing to operate the existing generating fleet in compliance with applicable law, including applicable environmental requirements, to various unit retirement and replacement configurations. Any retirement and replacement configuration that results in a lower PVRR than the current resource portfolio would not harm the Companies' ratepayers and would therefore meet this Senate Bill 4 requirement.

3.3.2 How the Companies' CPCN-DSM Proposals Meet the No Harm to Utility Ratepayers Requirement

The Companies' CPCN-DSM analysis in Exhibit SAW-1 and its supporting documentation in Exhibit SAW-2 demonstrates at length that the Companies' proposed CPCN-DSM portfolio optimizes cost and reliability for customers. In particular, it demonstrates that the PVRR for the proposed CPCN-DSM portfolio is lower than the PVRR of continuing to operate the existing generating fleet, though it assumed the retirements of Mill Creek 1, Haefling 1-2, and Paddy's Run 12.

For Senate Bill 4 analysis purposes, the Companies performed additional PVRR calculations summarized in Table 8 below, which demonstrate that the Companies' proposed CPCN-DSM portfolio will not harm customers; rather, including all known direct and indirect costs that affect revenue requirements (and therefore customers' bills), it will likely result in substantial PVRR benefits to customers. Note that the coal-to-gas ("CTG") ratio scenarios presented in Table 8 are the same as those presented in Exhibit SAW-1 and supported by Exhibit SAW-2 in the CPCN-DSM proceeding, and the underlying cost data and other relevant data and assumptions supporting the results presented in Table 8 are the same as those used in the Companies' PVRR modeling in the CPCN-DSM case with the addition of the following cost data for units that were assumed to be retired in the CPCN-DSM case: (1) additional capital and O&M costs required to allow Mill Creek 1 to continue to operate through 2050 (i.e., stay-open costs, SCR, ELG compliance, and cooling tower costs) and (2) additional stay-open costs through 2050 for Haefling 1-2 and Paddy's Run 12.[41]

[41] Stay-open costs through 2050 for Mill Creek 1 were included in the data the Companies used in their CPCN-DSM modeling, but the models in that proceeding did not use data beginning in 2025 due to the assumption that Mill Creek 1 would retire by the end of 2024. That assumption was consistent with the evidence and final orders in the Companies' 2020 ECR cases.

Table 8: Incremental PVRR ($M)

	Portfolio	Mid CTG Ratio: Low Gas, Mid CTG	Mid CTG Ratio: Mid Gas, Mid CTG	Mid CTG Ratio: High Gas, Mid CTG	Avg of Mid CTG Scenarios	Cumulative vs. Portfolio 0		Other CTG Ratios: Low Gas, High CTG	Other CTG Ratios: High Gas, Low CTG	Other CTG Ratios: High Gas, Curr CTG	Avg Excl High Gas, Curr CTG
0	No Retirements; Add DSM	NA	NA	NA	NA	NA		NA	NA	NA	NA
Fossil retirements and dispatchable electric generating replacements:											
1	Ret MC1-2; Add DSM/MC5	(74)	(54)	(37)	(55)	(55)		(148)	183	(1,590)	(26)
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	(273)	(289)	(350)	(304)	(359)		(348)	(210)	(1,726)	(294)
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	(2)	(2)	(2)	(2)	(361)		(2)	(2)	(2)	(2)
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	(87)	(79)	(58)	(75)	(435)		(91)	(32)	(163)	(69)
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	(227)	(183)	(48)	(153)	(588)		(223)	25	(125)	(131)
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	165	93	(78)	60	(528)		153	(62)	(221)	54
Add dispatchable non-generating resources:											
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	133	131	100	121	(407)		135	74	112	115
Add non-dispatchable electric generating resources:											
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	21	(226)	(811)	(339)	(745)		0	(784)	(1,191)	(360)
	Cumulative vs. Portfolio 0	**(344)**	**(609)**	**(1,284)**	**(745)**	**NA**		**(524)**	**(807)**	**(4,906)**	**(713)**

3.4 Effect of Federal Financial Incentives or Benefits on Retirement Decisions (Senate Bill 4 Section 2(2)(c))

Senate Bill 4 states in Section 2(2)(c) that part of what a utility must show to overcome the rebuttable presumption against retiring a fossil fuel fired electric generating unit is that "[t]he decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency." The Companies' decision to retire the seven units at issue here do not result from such incentives; indeed, the Companies are unaware of any such financial incentives or benefits for retiring fossil fuel fired electric generating units. There are, however, federal tax credits provided for certain renewable generation resources included in the CPCN-DSM proposals. As these inure completely to the benefit of customers, they must be included in any reasonable PVRR analysis to appropriately reflect the cost of such generation supply alternatives. It would be unreasonable and unfair to customers to have such benefits eliminated from consideration when evaluating generation units. Therefore, the Companies' CPCN-DSM proposals fully satisfy this Senate Bill 4 requirement.

3.5 Demonstration of Cost Savings Resulting from Direct and Indirect Costs of Retirements (Senate Bill 4 Section 2(3))

Section 2(3) of Senate Bill 4 states:

> The utility shall at a minimum provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit.

3.5.1 The Cost Savings Resulting from Direct and Indirect Costs of Retirements Requirement

The purpose of Senate Bill 4's requirement to "provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit" ***is precisely to*** "demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit." In other words, if a possible "cost[] of retiring the electric generating unit" would have no effect on customers' rates, it is not included in the analysis. But to the extent direct costs (e.g., unit decommissioning costs) or indirect costs (e.g., replacement capacity costs) would affect customers' rates, this analysis does account for them in the Companies' PVRR calculations and the underlying data supporting those calculations.[42] Table 9 below shows the categories of such direct and indirect costs included in the Companies' PVRR calculations:

[42] *See* Case No. 2022-00402, May 2023 Update to Exhibit SAW-1 (May 4, 2023); Case No. 2022-00402, Direct Testimony of Stuart A. Wilson, Exhibit SAW-2 (Dec. 15, 2022).

Table 9: Direct and Indirect Costs of Unit Retirements Considered in Analysis[43]

Cost Item	Direct Costs	Indirect Costs
Generation Production Costs	Variable fuel and reagent costs directly consumed by affected units.	Variable fuel and reagent costs directly consumed by other existing and proposed units in the Companies' fleet, and the cost of purchased power such as OVEC and solar PPAs.
Coal Combustion Residuals (CCR) Beneficial Re-use	Revenue of CCR sales associated with affected units.	Revenue of CCR sales associated with other existing units in the Companies' fleet.
Existing Unit Undepreciated Capital	Undepreciated capital cost associated with past investment in affected units.	Undepreciated capital cost associated with past investment in other existing units in the Companies' fleet.
Existing Unit Stay-Open Costs	Ongoing capital and fixed O&M associated with affected units.	Ongoing capital and fixed O&M associated with other existing units in the Companies' fleet.
Environmental Compliance Costs	Capital and O&M associated with compliance costs of affected units for new regulations, such as SCRs to comply with the Good Neighbor Plan, or incremental ELG spend to allow continued operation of Mill Creek 1.	
New Generation Capital and Stay-Open Costs		Capital and O&M associated with new generation assets.

Therefore, demonstrating that a portfolio has a lower PVRR than continuing to operate and maintain the existing portfolio (Portfolio 0) meets the requirements of Senate Bill 4 Section 2(3). That is precisely what retiring and replacing the seven fossil fuel-fired electric generating units as the Companies proposed in the CPCN-DSM case does: as shown in Table 8 in Section 3.3.2 above, the Companies' CPCN-DSM portfolio results in hundreds of millions of dollars of PVRR savings for customers.

4 Conclusion: The Proposed Fossil Unit Retirements, as Part of the Companies' Total Set of Proposals in their CPCN-DSM Applications, Meet All Requirements of Senate Bill 4

The analysis presented here confirms the results of the Companies' analysis in the CPCN-DSM proceeding: the Companies' proposed unit retirements and replacement resources are economical for customers and enhance system reliability and resilience. More precisely, the proposed unit retirements and replacement resources will result in significant PVRR savings for customers over nearly three decades, maintain system reliability year-round, maintain reserve margins in excess of minimum target levels, and improve system

[43] Cost items reflected in this table are the same as those reflected in Table 4 from the Resource Assessment (May 2023 Update to Exhibit SAW-1 in the CPCN-DSM case), with the additions of Coal Combustion Residuals (CCR) Beneficial Re-use and Existing Unit Undepreciated Capital. These additional items were reflected in the Resource Assessment, just not explicitly listed in Table 4.

resilience with improved start times, ramp rates, and dispatchable capacity. These results fully satisfy the requirements of Senate Bill 4 to receive Commission approval for the retirement of fossil fuel-fired electric generating units.

5 Appendix A: Background Information on Fossil Units the Companies Anticipate Retiring or Plan to Retire by 2028

The Companies are seeking Commission approval to retire a total of seven fossil fuel fired electric generating units, four of which are coal-fired units (E.W. Brown Unit 3, Ghent Unit 2, and Mill Creek Units 1 and 2) and three of which are natural gas simple-cycle combustion turbines (Haefling Units 1 and 2 and Paddy's Run Unit 12). All of these units are aging and at or near the end of their economic lives, and all of the coal-fired units except Brown 3 would require significant investment in environmental compliance facilities to continue operating in both the near and long term. And Brown 3 requires a major overhaul in 2027 for reliable operation in 2028 and beyond.

As shown in Table 10 below, all seven of the units are over 50 years old or will be by their proposed retirement dates, and they are approaching the end of their useful lives. Although the units could theoretically operate beyond their currently expected useful lives, doing so would require a higher level of capital investments that would harm the Companies' customers in the form of increased rates.

Table 10: Age of Proposed Retiring Units

Unit	Age as of 1/1/2022	Age as of 1/1/2035	Age as of 1/1/2050
Paddy's Run 12	53	66	81
Haefling 1-2	51	64	79
Brown 3	50	63	78
Mill Creek 1	49	62	77
Mill Creek 2	47	60	75
Ghent 2	44	57	72

To properly evaluate the economics of the existing fleet, the Companies identified the types of projects and associated costs that would be needed to extend the lives of units to 2050. To be clear, the Companies are not proposing to extend these units' lives; rather, this analytical approach is necessary to properly evaluate the fleet's economics. Table 11 below contains stay-open costs for these seven units. Note that the costs in Table 11 necessary to continue operating Mill Creek 1, Haefling 1-2, and Paddy's Run 12 in 2025 and beyond were not included in the PVRR analyses in the CPCN-DSM case. Stay-open costs for existing generating units include each unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating a unit and are avoided if a unit is retired. Costs that are shared by all units at a station (i.e., "common" costs) are allocated to units in proportion to how they would be reduced as units retire.[44] Stay-open costs include costs for routine maintenance and

[44] The allocation of common costs requires an assumed order of retirement at a given station. The lack of SCRs for Ghent 2 and Mill Creek 2 results in those units being retired first relative to other units at their respective stations. The remaining units have the same controls and similar efficiencies (with the exception of Trimble County 2, which is a supercritical unit and the most efficient in the Companies' coal fleet), so the likely retirement order would be driven by age of the units. At Ghent, this results in a retirement order of Ghent 2 first, followed by Ghent 1, then Ghent 3, and finally Ghent 4. At Mill Creek, this results in a retirement order of Mill Creek 2 first, followed by Mill Creek 3, and finally Mill Creek 4. At Trimble, this results in a retirement order of Trimble County 1 first, followed by Trimble County 2.

major overhauls, and do not include carrying costs for prior investments or costs for projects that would not be affected by unit retirements in this analysis, such as ash pond closures. In the case of Mill Creek 1, stay-open costs include the costs of SCR for Good Neighbor Plan Compliance, the costs to comply with the Effluent Limitation Guidelines ("ELG Rule"), and other costs included in the retirement analysis for Mill Creek 1 in the Companies' 2020 ECR cases, including the addition of a cooling tower to comply with Clean Water Act 316(b) regulations.[45] In the case of Mill Creek 2 and Ghent 2, stay-open costs include the costs of SCR for Good Neighbor Plan Compliance. Finally, Table 11 differentiates between "standard" major overhaul costs and the costs for projects that would be needed to operate the unit through 2050.[46] When evaluating the retirement of these coal units, the Companies assume that costs for routine maintenance and major overhauls will be reduced in the years leading up to a unit's retirement and that all future spending would be avoided after a unit's retirement.

[45] Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

[46] Examples of projects that would be needed to extend the life of a generating unit are replacement of major high temperature components such as superheater and reheater headers and seamed main steam and hot reheat piping, condenser re-tubing, generator stator rewinds, generator step-up transformer replacements, and ID fan variable frequency drive replacements.

Table 11: Total Stay-Open Costs ($M)

Year	Mill Creek 1						Mill Creek 2				Ghent 2				Brown 3			Paddy's Run 12	Haefling 1-2
	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Env. Comp. Costs (SCR)	Cooling Tower	ELG	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Env. Comp. Costs (SCR)	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Env. Comp. Costs (SCR)	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Ongoing Costs	Ongoing Costs
2023	10	0	0	2	8	0	11	0	0	2	12	0	0	3	27	0	0	0.1	0.1
2024	5	0	0	16	1	0	21	0	0	16	23	0	0	30	30	0	0	0.1	0.0
2025	14	0	0	47	1	8	15	0	0	47	12	0	0	76	31	0	0	0.1	0.0
2026	5	0	0	45	1	17	18	11	0	45	22	0	0	18	35	0	0	0.1	0.0
2027	10	11	0	1	1	0	14	0	0	1	17	36	0	1	32	26	0	0.1	0.0
2028	5	0	0	1	1	0	18	0	0	1	13	0	0	1	32	0	0	0.1	0.1
2029	14	0	37	1	1	0	14	0	37	1	14	0	0	1	35	0	32	0.1	0.1
2030	7	0	23	1	1	0	21	0	23	1	25	0	0	1	36	0	38	0.1	0.1
2031	11	0	22	1	1	0	17	0	22	1	19	0	0	1	36	0	22	0.1	0.1
2032	7	0	0	1	1	0	21	0	0	1	19	0	0	1	38	0	0	0.1	0.1
2033	13	0	2	1	1	0	17	0	2	1	20	0	25	1	38	0	2	0.1	0.1
2034	8	0	18	1	1	0	22	16	18	1	20	0	42	1	40	0	0	0.1	0.1
2035	13	17	0	1	1	0	18	0	0	1	21	24	23	1	40	30	0	0.1	0.1
2036	8	0	0	1	1	0	22	0	0	1	21	0	42	1	41	0	0	0.1	0.1
2037	14	0	0	1	1	0	19	0	0	1	22	0	8	1	42	0	0	0.1	0.1
2038	8	0	0	2	1	0	25	0	0	2	22	0	0	2	43	0	14	0.1	0.1
2039	12	0	0	2	1	0	20	0	0	2	22	0	14	2	44	0	0	0.1	0.1
2040	9	0	0	2	1	0	24	0	0	2	23	0	0	2	45	0	0	0.1	0.1
2041	15	0	15	2	1	0	21	0	15	2	23	0	0	2	46	0	0	0.1	0.1
2042	9	0	0	2	1	0	25	19	0	2	24	0	0	2	48	0	11	0.1	0.1
2043	16	19	0	2	1	0	21	0	0	2	24	28	0	2	48	35	0	0.1	0.1
2044	9	0	0	2	1	0	27	0	0	2	25	0	0	2	50	0	0	0.1	0.1
2045	17	0	12	2	1	0	22	0	12	2	26	0	0	2	50	0	0	0.1	0.1
2046	10	0	0	2	1	0	30	0	0	2	26	0	0	2	52	0	0	0.1	0.1
2047	14	0	0	2	1	0	23	0	0	2	27	0	0	2	52	0	0	0.1	0.1
2048	10	0	0	2	1	0	29	0	0	2	27	0	0	2	55	0	0	0.1	0.1
2049	14	0	0	2	2	0	24	0	0	2	28	0	0	2	55	0	0	0.1	0.1
2050	10	0	0	2	2	0	25	23	0	2	30	0	0	2	57	0	0	0.1	0.1

Exhibit SB4-2

Certain information in the exhibit is confidential and proprietary and is provided under seal pursuant to a petition for confidential protection.