Generation Services Engineering 2015 Depreciation Study Evaluation

3/4/16

Methodology

Many factors influence the end of life for a generating station. To complete this analysis the following assumptions were made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated in accordance with good industry practices with required renewals and replacements made in a timely manner

The generating stations were reviewed at a high level and although many individual components could fail it was decided that those would not constitute an "end of life" event and could be mitigated. The boiler drum and turbine/generator were the two components/systems identified where catastrophic failure would be consideration for retirement.

Although the boiler is a complex system with many elements, the boiler drum is a large single component with approximately 240k hours of defined life and is significantly influenced by thermal cycling. Electric Power Research Institute (EPRI) studies indicate that after approximately 1,700 normal start/stop cycles the risk of a critical flaw developing is greatly increased.

The turbine/generator is a single system, whose failure could lead to significant downtime and repair/replacement costs. Several key factors are taken into consideration when evaluating the generator such as insulation type, winding age, recent inspection findings, and test results. Wear, cracking, and blade condition are key considerations for the turbine.

Review

The depreciation review process conducted by Generation Engineering consisted of evaluating key parameters (i.e. pressures, temperatures, voltages etc..) with equipment condition (i.e. inspection data, EPRI, IEEE, etc..) to provide a risk based assessment regarding the likelihood of equipment failure as compared to industry norms.

Boiler
EPRI states:

- A critical flaw size crack appears on average at around 30 years of service (240,000 hours).
- The average number of cycles of a coal drum unit is expected to be 1,700 normal starts/stops to drive a critical flaw to failure.
- Natural Circulation boilers are more susceptible to ligament cracking than are Forced Circulation boilers.

The boiler review included previous inspection reports and a review of design vs typical operating temperatures and pressures.

Generator
Generators are regularly inspected and electrically tested. Those results were reviewed along with any other known issues. In most cases where the generator winding was beyond design life, no known issues have been observed and no concerns exist regarding condition. However, assessments of Brown 1 and Brown 2 have identified discounts on their expected end of life due to generator condition.

Brown 1 has asphalt insulation and an observed shorted turn in the field winding. Electrical test results have been within normal expectations, however the armature winding is 59 years old with a design life of 30.

Brown 2 inspection and electrical test results have been as expected, however the armature winding has been in service for 52 years with an expected life of 30.

Turbine
Turbines are inspected on a routine basis with periodic repairs/overhauls to bring the unit to as designed operation. To-date, no issues have been observed which did not allow a return to as designed operation.

Summary

Based on EPRI's research and the Generation Services Engineering review of units comparing their data, the boiler drum should not reduce the retirement year of each unit. While the EPRI “average end of drum life” for MC3 & MC4 are just short of the previous end of life depreciation study, the difference is not significant when considering these are typical and average numbers used from the analysis.

The end of life for Brown Unit 1 has been reduced 5 years from 2028 to 2023. The end of life for Brown Unit 2 has been reduced 5 years from 2034 to 2029.

There are no concerns regarding Turbine condition impacting unit end of life.

Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation

5/25/18

Methodology

Many factors influence the end of life for a generating station. To complete this analysis the following assumptions were made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained
- Future changes in environmental regulations are a consideration for unit retirement
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated in accordance with good industry practices with required renewals and replacements made in a timely manner

The steam generating units were reviewed at a high level and although many individual components could fail it was decided that those would not constitute an "end of life" event and could be mitigated. The boiler drum and turbine/generator were the two components/systems identified where catastrophic failure would be consideration for retirement.

Although the boiler is a complex system with many elements, the boiler drum is a large single component with approximately 240k hours of defined life and is significantly influenced by thermal cycling. Electric Power Research Institute (EPRI) studies indicate that after approximately 1,700 normal start/stop cycles the risk of a critical flaw developing is greatly increased.

The turbine/generator is a single system, whose failure could lead to significant downtime and repair/replacement costs. Several key factors are taken into consideration when evaluating the generator such as insulation type, winding age, recent inspection findings, and test results. Wear, cracking, and blade condition are key considerations for the turbine.

Review

The depreciation review process conducted by Generation Engineering consisted of evaluating key parameters (i.e. pressures, temperatures, voltages etc..) with equipment condition (i.e. inspection data, EPRI, IEEE, etc..) to provide a risk based assessment regarding the likelihood of equipment failure as compared to industry norms.

Boiler

EPRI states:

- A critical flaw size crack appears on average at around 30 years of service (240,000 hours).
- The average number of cycles of a coal drum unit is expected to be 1,700 normal starts/stops to drive a critical flaw to failure.
- Natural Circulation boilers are more susceptible to ligament cracking than are Forced Circulation boilers.

The boiler review included previous inspection reports and a review of design vs typical operating temperatures and pressures.

Generator

Generators are regularly inspected and electrically tested. Those results were reviewed along with any other known issues. In most cases where the generator winding was beyond design life, no known issues have been observed and no concerns exist regarding condition.

Turbine

Turbines are inspected on a routine basis with periodic repairs/overhauls to bring the unit to as designed operation. To-date, no issues have been observed which did not allow a return to as designed operation.

Summary

Based on EPRI's research and the Generation Services Engineering review of units comparing their data, the boiler drum should not reduce the retirement year of each unit. While the EPRI "average end of drum life" for MC3 & MC4 are just short of the previous end of life depreciation study, the difference is not significant when considering these are typical and average numbers used from the analysis.

There are no known concerns regarding generator or turbine condition impacting unit end of life across the fleet.

No changes are recommended to existing unit retirement dates as identified in the 2015 study.

Analysis of Generating Unit Retirement Years

PPL companies

Generation Planning & Analysis
October 2020

Contents

1. Summary

The Companies own and operate approximately 7,561 MW of summer net generating capacity in Kentucky. The generating system consists of four coal-fired generating stations: the E.W. Brown Generating Station in Mercer County, the Ghent Generating Station in Carroll County, the Mill Creek Generating Station in Jefferson County, and Trimble County Generating Station. The purpose of this study was to examine the existing retirement dates for certain coal-fired generating units as reflected in existing depreciation rates based on maintaining system reliability to determine whether they were reasonable based on the changes in operational and economic circumstances and, if not, to determine reasonable retirement years. This report explains the basis for the updates to the retirement years for the generating units shown in Table 1. The updated retirement years are estimates of the currently expected operating lives of these generating units. Actual retirement dates may vary depending on the circumstances involving the generating unit and operational factors that may emerge in the future. The Companies will continue to assess these retirement dates.[1]

Table 1 - Retirement Years, Current vs. Updated

	Retirement Years	
	Current	**Updated**
Brown Unit 3 ("BR3")	2035	2028
Ghent Unit 4 ("GH4")	2038	2037
Mill Creek Unit 1 ("MC1")	2032	2024
Mill Creek Unit 2 ("MC2")	2034	2028
Mill Creek Unit 3 ("MC3")	2038	2039
Mill Creek Unit 4 ("MC4")	2042	2039
Trimble Count Unit 1 ("TC1")	2050	2045

2. Mill Creek Unit 1

As presented in LG&E's 2020 ECR Plan, due to the cost of complying with Effluent Limitation Guidelines ("ELG"), MC1 will be retiring at the end of 2024.[2] Retiring MC1 on December 31, 2024 is lower cost than investing in the water treatment facilities that would be required to comply with ELG and continue its operation beyond December 31, 2024. As a result, it is no longer reasonable to continue to use 2032 as the retirement year for MC1. Based on current capacity and demand projections, the Companies are not planning for immediate replacement of MC1's generating capacity.

3. Ghent Unit 4, Mill Creek Units 3 and 4, and Trimble County Unit 1

Based on their current retirement years, GH4, MC3, and MC4 would be the last coal-fired units to retire before the retirements of the newer Trimble County units. The Companies have decided to delay the

[1] The results of this study were provided to Mr. John J. Spanos for purposes of independent assessment in connection with possible changes to existing depreciation rates.
[2] *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 (Ky. PSC Mar. 31, 2020).

retirement year for MC3 by one year and to advance the retirement years by one year for GH4 and three years for MC4. These changes align the retirement years of Ghent Units 3 and 4 in 2037 and Mill Creek Units 3 and 4 in 2039 and reduce major maintenance costs on MC4 in 2038. This alignment also allows for planning a more orderly closure of the Ghent and Mill Creek stations and the potential for more cost-effective replacement of their collective capacities through economies of scale and coordinated procurement, construction or both. The Companies also are advancing the retirement year for TC1 to 2045, reflecting an expected age at retirement of 55 years, which better aligns with the expected lives of the Companies' other remaining coal units.

4. Mill Creek Unit 2 and Brown Unit 3

4.1. Mill Creek Unit 2 Background

2015 Ozone NAAQS

The Mill Creek station is in Jefferson County, Kentucky and currently operates four coal-fired units. Jefferson County is currently classified as marginal non-attainment to the 2015 Ozone National Ambient Air Quality Standard ("NAAQS") with a compliance date of August 2021. In 2020, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District ("LMAPCD") imposed additional daily limitations on nitrogen oxides ("NO_x") emissions at the Mill Creek station for the months of May through October. Despite the Companies' efforts to meet these limits, there were exceedances of the 70 ppb ozone standard in the Jefferson County area during the 2020 ozone season. LMAPCD has stated that Jefferson County will not be "in compliance" with the 2015 Ozone NAAQS by August 2021 due to these exceedances in 2020. LMAPCD currently anticipates reclassification to moderate non-attainment in 2022 and Title V facilities in Jefferson County will be required to implement NO_x Reasonable Available Control Technology ("RACT") by March 1, 2023. In the interim, the Companies expect that the ozone season NO_x limit for the MC station will remain in place pending development of the NO_x RACT standard. Therefore, LG&E will likely be limited to operating either MC1 or MC2 (but not both) during the ozone season (i.e., April through October) until MC1 retires.

Upon reclassification to moderate non-attainment with the 2015 Ozone NAAQS, Jefferson County will have a moderate non-attainment compliance date of August 3, 2024. The State Implementation Plan ("SIP") must be amended to include the RACT standards by April 2024. The NO_x emission reduction associated with the implementation of RACT at Mill Creek Station is expected to be similar to the mode of operation at Mill Creek during the summer of 2020. However, during the summer of 2020, there were still exceedances of the 70 ppb ozone standard in the Jefferson County area.

Continued non-attainment past the 2024 compliance date will result in Kentucky reevaluating RACT for the Jefferson County area in order to further reduce NO_x emissions or cause the non-attainment area to be reclassified to serious non-attainment. Such a reclassification would require additional NO_x emission reductions, which must be demonstrated by August 2027. LG&E will likely be required to install additional NO_x controls on MC2 such as selective catalytic reduction ("SCR") to achieve these reductions and continue to operate the unit.

2025 Ozone NAAQS

The Clean Air Act requires that NAAQS be evaluated every five years. The ozone and $PM_{2.5}$ NAAQS were reevaluated in 2020. EPA retained the current standard of 70 ppb for ozone and 12.0 $\mu g/m^3$ for $PM_{2.5}$. Prior to EPA's proposal to retain the current standards, many environmental groups and members on the Clean Air Scientific Advisory Committee presented data for a lower standard of 65 – 68 ppb for ozone and

10-11 µg/m^3 for $PM_{2.5}$. Both standards will be reevaluated again in 2025. At this time, there is every reason to expect both standards will be lowered following the reevaluation in 2025. Jefferson County is likely not to meet either standard. Therefore, even if Jefferson County has achieved attainment of the 70 ppb ozone standard by August 2024, it is likely that the standard would be lowered in 2025, and, once again, Jefferson County will be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources, including the Mill Creek station. Based on the timeframe for implementing lowered NAAQS, it is likely additional controls would be required for MC2 by 2029.

CSAPR Requirements

An additional contingency arises under EPA's interstate transport rules for NO_x that ensure that the northeastern states are meeting the ozone standards and are not exceeding these standards due to interstate transport. EPA's Cross-State Air Pollution Rule ("CSAPR") regulations were developed to accomplish this requirement. Currently certain areas in the northeastern states are not meeting the 2008 (75 ppb) ozone standard. To address this issue, on October 15, 2020, EPA issued the proposed Revised CSAPR Update rule, which will significantly reduce the NO_x allowances issued to Kentucky. Based on their modeling, electric generating units in Kentucky have an impact exceeding a screening threshold on the northeastern non-attainment areas. Additional controls at our non-SCR-equipped units may be required because of the reduced allocation of NO_x emissions allowances for Kentucky and the LG&E and KU fleet. Additional allowances will be limited under the proposed rule; and trading will be restricted to the twelve states EPA is assigning to the "Group 3" Trading Group. Because this allowance reduction was necessary to meet the 2008 (75 ppb) standard by 2021, it is reasonable to expect that even greater NO_x reductions will be necessary in order to meet a 70 ppb ozone standard.

Regional Haze

A final environmental contingency is the possible changes from the Regional Haze 3rd Planning period. Mill Creek Units 3 and 4 have permit limits from the 1st planning period to meet the visibility criteria for Mammoth Cave National Park under the rule. Mill Creek did not have to take further restrictions for the 2nd planning period due to Kentucky visibility falling well below the glide path of visibility impaired days required by the regulation for 2030. EPA's requirements for implementation of the 3rd planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Kentucky is not currently below the glide path required in the next planning period. Because Mill Creek is relatively close to Mammoth Cave National Park, Units 1 and 2 could be required in the next planning period to evaluate additional controls to improve visibility at the park.

In summary, the Companies expect that SCR will be required on MC2 between 2027 and 2029 to comply with current and future NAAQS. Uncertainty related to the EPA's CSAPR regulations and the Regional Haze rule further supports this assumption. Therefore, the Companies have assumed that SCR will be required on MC2 in 2028 to operate MC2 beyond 2028. The SCR investment is approximately $135 million. Additionally, an investment in major maintenance will be required in 2026 if MC2 is planned to remain in service beyond 2028. As of 2020, MC2 is 46 years old. Its current retirement year is 2034. This analysis will determine whether either of these future investments is economically warranted and if they are not, then the current 2034 retirement year is not reasonable, and a new date must be determined.

4.2. Brown Unit 3 Background

As of 2020, BR3 is 49 years old. BR3's current retirement year is 2035. Since the retirement of Brown Units 1 and 2 in 2019, BR3 is the single remaining coal unit at the Brown Station. BR3's delivered fuel cost is higher than that of the Companies' other coal units because coal is only delivered by rail. The higher delivered fuel cost causes BR3 to operate at a significantly lower capacity factor.[3] It is outfitted with full emissions controls and its last major maintenance overhaul was in 2019.[4] A total investment in major maintenance of approximately $31 million will be required in 2026 and 2027 to continue its operation beyond 2028. An evaluation of those investments is necessary to determine if BR3's current retirement year is reasonable, or if a new retirement year should be set based on the ability to operate the unit absent these major maintenance investments.

4.3. Analysis Methodology

Given the expectations regarding compliance with environmental regulations, forecasts for required future investments, the resultant physical life of the units, and the need for replacement generation, the Companies evaluated advancing the retirement years for MC2 and BR3. The analysis was performed to determine whether the existing retirement years are reasonable and if not to determine reasonable retirement years based on current information.

Before committing to actual retirement dates, the Companies plan to evaluate the ability to replace the units as needed to continue to supply reliable, reasonable cost energy based on actual proposals from third party suppliers (gathered via a request for proposals) and self-build alternatives. The results of this process would be filed with the Kentucky Public Service Commission in an application for a Certificate of Public Convenience and Necessity.

As set forth above, MC2 is expected to require an approximately $135 million investment in SCR on or before 2028 to continue operation beyond 2028. Accordingly, the Companies are advancing the MC2 retirement year to 2028. Likewise, a 2028 retirement year was selected for BR3 because 2028 is the longest BR3 can operate without the investments in 2026 and 2027 for major maintenance. The present value of revenue requirements ("PVRR") for each alternative was computed as the PVRR of the following cost and revenue items:

1. Generation system production costs
2. Existing unit stay-open costs, including ELG compliance costs and associated O&M
3. Existing unit revenues from the sale of coal combustion residuals ("CCR")
4. Capital and stay-open costs for replacement generation units

Generation production costs for the LG&E and KU system were computed using the PROSYM production cost model from Hitachi ABB. The PVRR for all alternatives include the full PVRR for capital expenditures, even when a unit is retired before it is fully depreciated. The analysis also assumes that MC2 and BR3 would otherwise be retired by their current retirement years, 2034 and 2035, respectively. Therefore, later retirement is assumed to defer the cost of any replacement generation, but not eliminate this cost altogether. The Companies initially evaluated the retirement year for MC2, given the NAAQS compliance issues and the high cost of investing in a SCR. The Companies then evaluated the retirement year for Brown 3.

[3] BR3's capacity factor was 28%, 35%, and 25%, in 2017, 2018, and 2019, respectively. It is forecasted to operate at a capacity factor of 24%, 22%, and 26% in 2021, 2022, and 2023, respectively.
[4] BR3's emissions controls include low NO_x burners, SCR, dry electrostatic precipitator, dry sorbent injection, powdered activated carbon injection, pulse jet fabric filter, and dry flue gas desulfurization.

For this analysis, the Companies assumed that MC2 and BR3 would be replaced with capacity from simple-cycle combustion turbines ("CTs") to create a generation portfolio that is minimally compliant for reliability, obviating the need to consider a range of fuel prices or a range of potential replacement alternatives. The point of this study was not to identify a potentially optimal future portfolio. As mentioned above, the Companies will issue a request for proposals to determine the optimal replacement resources and help inform the actual retirement dates for each of these units. The goal of this study is to determine whether the current estimated retirement years for MC2 and BR3 are reasonable given current information regarding the likely costs of operating the units to the currently projected dates.

4.4. Analysis

A primary consideration when contemplating unit retirements is the need to maintain a sufficient reserve margin for summer peak reliability. The following tables show the calculation of annual forecasted summer reserve margins and include the following assumptions:

- The Companies' 2021 Business Plan peak demand forecast;
- MC2 (297 MW) is unavailable from April through October in 2021-2024 due to the expected continuing limitation on NO_x emissions from the Mill Creek station;
- MC1 (300 MW) retires at the end of 2024; and
- Zorn (14 MW) retires at the end of 2021; the Companies remaining small-frame CTs (59 MW)[5] retire at the end of 2025.
- For presentation purposes, no additional retirements beyond 2030 are assumed.

Table 2 shows the forecasted summer reserve margins through 2035 with no coal unit retirements after MC1's retirement at the end of 2024. Table 3 shows the reserve margins assuming that MC2 retires in 2028 without replacement. Because the reserve margin remains above the lower end of the Companies' target reserve margin range of 17 percent to 25 percent, it is assumed that MC1 and MC2 can be retired without replacement. Table 4 shows the reserve margins assuming that BR3 also retires in 2028 without replacement. To maintain a 17 percent reserve margin in 2028, 278 MW of replacement capacity is needed. As a proxy for commercially available replacement capacity, the Companies assumed that two CTs similar to the Companies' existing CTs at the Trimble County station would provide this replacement capacity with net summer ratings of 159 MW each. Table 5 shows that the forecasted reserve margins with this additional 318 MW of capacity are within the Companies' target reserve margin range.

[5] The remaining small-frame CTs are Haefling 1 (12 MW), Haefling 2 (12 MW), Paddy's Run 11 (12 MW), and Paddy's Run 12 (23 MW).

Table 2 - Reserve Margin with MC1 and Small Frame CTs Retirements (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gross Peak Load	6,399	6,433	6,430	6,428	6,420	6,406	6,391	6,369	6,358	6,344	6,332	6,324	6,325	6,320	6,320
Energy Efficiency/Demand Side Mgmt.	(288)	(294)	(300)	(305)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Existing Generation Resources	7,711	7,712	7,712	7,712	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713
Curtailable Load (CSR)	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Direct Load Control (DLC)	63	61	60	58	56	55	53	52	50	49	48	47	46	45	44
Small-Frame CT Retirements	0	(14)	(14)	(14)	(14)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
MC2 Unavailable	(297)	(297)	(297)	(297)											
MC1 Retirement					(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Total Resources Net of MC1 and Small-Frame CTs Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,519**	**7,517**	**7,516**	**7,515**	**7,514**	**7,513**	**7,512**	**7,511**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**24.1%**	**24.3%**	**24.6%**	**24.8%**	**25.0%**	**24.9%**	**25.0%**	**25.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 3 - Reserve Margin with Incremental MC2 Retirement in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Total Resources Net of MC1 and Small-Frame CTs Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,519	7,517	7,516	7,515	7,514	7,513	7,512	7,511
MC2 Retirement in 2028								(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,222**	**7,220**	**7,219**	**7,218**	**7,217**	**7,216**	**7,215**	**7,214**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**19.2%**	**19.4%**	**19.7%**	**19.9%**	**20.0%**	**20.0%**	**20.1%**	**20.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 4 - Reserve Margin with Incremental BR3 Retirement in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	6,111	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,222	7,220	7,219	7,218	7,217	7,216	7,215	7,214
BR3 Retirement in 2028								(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	6,810	6,808	6,807	6,806	6,805	6,804	6,803	6,802
Reserve Margin %	24.4%	23.6%	23.8%	23.9%	24.1%	23.4%	23.7%	12.4%	12.6%	12.8%	13.0%	13.2%	13.1%	13.2%	13.2%
Reserve Margin Deficit vs. 17%	NA	NA	NA	NA	NA	NA	NA	278	267	252	239	231	233	228	229

Table 5 - Reserve Margin with Capacity Addition in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	6,111	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	6,810	6,808	6,807	6,806	6,805	6,804	6,803	6,802
Additional 2 CTs								+318	+318	+318	+318	+318	+318	+318	+318
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,128	7,126	7,125	7,124	7,123	7,122	7,121	7,120
Reserve Margin %	24.4%	23.6%	23.8%	23.9%	24.1%	23.4%	23.7%	17.7%	17.8%	18.1%	18.3%	18.5%	18.4%	18.5%	18.5%
Reserve Margin Deficit vs. 17%	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

4.4.1. Mill Creek Unit 2

MC2's current retirement year is 2034. As discussed in Section 4.1, the Companies expect that SCR will be required for MC2 by 2028 in order to continue operating beyond 2028. The cost of SCR for MC2 is estimated to be at least $135 million in 2020 dollars. Furthermore, an investment in major maintenance in 2026 of $5.5 million in capital and $5.0 million in O&M costs would be required for MC2 to continue operating until 2034. Table 6 shows the difference in annual revenue requirements and PVRR between retiring MC2 in 2028 and 2034, assuming that the SCR and major maintenance expenditure could be avoided with the earlier retirement date. It is assumed that MC2 would otherwise retire in 2034, so there are no differences in revenue requirements in 2034 and beyond. Additional savings from retiring MC2 in 2028 result from avoiding MC2's stay-open costs, which are partially offset by production cost increases and foregone CCR sales revenue. Because MC2 can be retired without replacement as shown in Table 3, there are no incremental costs for new capacity to replace MC2. The total net PVRR ("NPVRR") impact of retiring MC2 in 2028 is a savings of $131.2 million.

Table 6 – Revenue Requirement Increases/(Savings) of Retiring MC2 in 2028 vs. 2034 ($M)[6]

	2026	2027	2028	2029	2030	2031	2032	2033
Production Costs	0	0	14.2	13.9	15.2	16.2	16.6	15.4
Stay Open Costs	0	0	(26.9)	(22.3)	(30.6)	(23.0)	(31.9)	(24.0)
SCR Cost	0	0	(166.1)	0	0	0	0	0
Major Maintenance	(11.7)	0	0	0	0	0	0	0
CCR Revenue	0	0	2.9	3.0	3.1	3.2	3.2	3.1
Total	**(11.7)**	**0**	**(175.9)**	**(5.5)**	**(12.3)**	**(3.6)**	**(12.1)**	**(5.5)**
NPVRR (2020)	**(131.2)**							

As a result of the likely need for the uneconomic investment in SCR in order to operate MC2 beyond 2028, it is unreasonable to continue to use 2034 as the retirement year. Given that compliance with likely additional NAAQS ozone standards would be required by 2028, that year represents a reasonable retirement year.

4.4.2. Brown Unit 3

BR3's current retirement year is 2035. An investment in major maintenance in 2026 and 2027 of $23.1 million in capital and $8 million in O&M costs would be required for BR3 to continue operating until 2035. Given the savings from retiring MC2 in 2028, the analysis of BR3's retirement year assumes that MC2 will retire in 2028. As shown in Table 4, retiring MC2 and BR3 in 2028 results in a minimum capacity need of 278 MW in 2028 to maintain a reserve margin within the Companies' target reserve margin range. To meet this reserve margin deficit, the Companies modeled replacement capacity comprising two CTs with the same characteristics as their existing Trimble County CTs, for a total additional capacity of 318 MW.

Table 7 shows the difference in annual revenue requirements and PVRR between retiring BR3 in 2028 and 2035. It is assumed that BR3 would otherwise retire in 2035, so there are no differences in revenue

[6] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

requirements in 2035 and beyond. In addition to the savings from avoiding the major maintenance investments in 2026 and 2027, retiring BR3 in 2028 results in the savings of its stay open costs through 2034 and a small amount of additional CCR revenue achieved by transferring some of BR3's generation to other coal units with more favorable CCR sales opportunities. These savings are more than offset on an annual basis by increases in production costs and the carrying cost of the required capacity additions. The NPVRR impact of retiring BR3 in 2028 is a revenue requirements savings of $40 million. Therefore, the existing 2035 retirement date is unreasonable and replacing it with 2028 is more reasonable given the potential to avoid major maintenance and lower overall revenue requirements with replacement generation by 2028.

Table 7 - Revenue Requirement Increases/(Savings) of Retiring BR3 in 2028 vs. 2034 ($M)[7]

	2026	2027	2028	2029	2030	2031	2032	2033	2034
Production Costs	0	0	3.3	5.7	5.4	6.1	6.8	7.8	5.0
Stay Open Costs	0	0	(40.3)	(39.5)	(40.5)	(41.3)	(42.1)	(43.0)	(43.8)
Major Maintenance	(13.9)	(22.1)	0	0	0	0	0	0	0
CCR Revenue	0	0	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.1)
Capacity Additions	0	0	29.5	30.1	30.6	31.2	31.7	32.3	32.9
Total	**(13.9)**	**(22.1)**	**(7.5)**	**(3.9)**	**(4.7)**	**(4.2)**	**(3.9)**	**(3.0)**	**(6.0)**
NPVRR (2020)	**(40.0)**								

The analysis focused only on maintaining system reliability. Therefore, when the Companies evaluate actual potential replacement alternatives for BR3, resource additions with the potential to lower energy costs (e.g., renewables and natural gas combined cycle) will provide additional information on the retirement date for BR3.

5. Appendix - Key Analysis Inputs and Assumptions

5.1. Existing Unit Stay-Open Costs

Stay-open costs for an existing unit include the unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating the unit and saved if the unit is retired. Table 8 lists total stay-open costs for the Companies' coal units assuming no early retirements. Costs that are shared by all units are allocated to units in proportion to how they would be reduced as units retire. Total stay-open costs include costs for regular maintenance and major maintenance; the analysis assumes the additional costs for major maintenance within eight years of retirement can be avoided. Beyond 2030, stay-open costs are assumed to escalate at two percent per year.

[7] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

Table 8 – Stay-Open Costs ($M, Nominal Dollars)

Total Stay-Open Costs	2026	2027	2028	2029	2030	2031	2032	2033	2034
MC2 – major maintenance	10.5	-	-	-	-	-	-	-	-
MC2 – annual	26.0	19.5	25.0	20.6	28.2	21.2	29.3	22.0	-
BR3 – major maintenance	11.4	19.6	-	-	-	-	-	-	-
BR3 – annual	35.8	37.1	38.7	37.9	38.9	39.7	40.4	41.3	42.1

5.2. CCR Revenue Assumptions

Coal combustion residuals ("CCR") include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in an onsite landfill. When sold to a third party, the beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2019, CCR sales revenues totaled $9 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price for CCR has increased. Table 9 lists the assumed sales prices for fly ash and gypsum from Mill Creek, Ghent, and Trimble County in this analysis. The sales prices are weighted average prices based on existing contracts rolling to market prices as existing contracts expire. The current market price for Mill Creek, Ghent, and Trimble County gypsum is approximately $10 per ton. The current market price for Mill Creek fly ash is approximately $32 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $25.60 per ton. The current market price for Ghent fly ash is approximately $30 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $24 per ton. The current market price for Trimble fly ash is approximately $9 per ton. CCR market prices are assumed to escalate at two percent per year.

Because Brown has no local market for either fly ash or gypsum, and because additional CCR loading systems at Brown are not economical, CCR revenue from Brown is assumed to be zero.

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Table 9 – Sales Price for CCR Sales ($/ton) (Confidential and Proprietary Information)

	Mill Creek		Ghent		Trimble	
Year	Fly Ash	Gypsum	Fly Ash	Gypsum	Fly Ash	Gypsum
2021	[redacted]					
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
2036						
2037						
2038						
2039						
2040						
2041						
2042						
2043						
2044						
2045						
2046						
2047						
2048						
2049						
2050						

Table 10 lists the percent of fly ash and gypsum produced at Brown and Mill Creek that is assumed to be sold to third parties.

Table 10 – Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum
Brown	0%	0%
Mill Creek	80%	97%

5.3. Fuel Prices

Fuel prices are assumed to escalate throughout the analysis period. Table 11 shows undelivered natural gas and coal price forecasts, which were developed for the Companies' 2021 Business Plan.

The Henry Hub natural gas price forecast reflects a blend of NYMEX market prices and a smoothed version of the Energy Information Administration's ("EIA's") 2020 Annual Energy Outlook ("AEO") High Oil and Gas Resource and Technology case through 2030, after which the smoothed EIA case was solely used. This case assumes higher resource availability and technological advancement, which results in lower production costs and continued growth in oil and gas production, compared to EIA's AEO 2020 Reference Case.

The Illinois Basin FOB mine coal price reflects a blend of coal price bids the Companies received, and a long-term price forecast developed by S&P Global Platts through 2025. In 2026 and beyond, the 2025 price was escalated by the coal escalation rate provided in the EIA's 2020 AEO High Oil and Gas Resource and Technology case.

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Table 11 – Fuel Prices, Undelivered (Nominal $/mmBtu) (Confidential and Proprietary Information)

	Natural Gas[8]	Coal[9]
2021	[redacted]	
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		

[8] Henry Hub.
[9] Illinois Basin FOB mine.

5.4. Replacement CT Assumptions

Table 12 shows the assumed characteristics of the CTs that were modeled as replacement capacity.

Table 12 – Replacement CT Assumptions (2020 In-Service; 2019 Dollars)

	Peaking Capacity (SCCT)
Capital Cost ($/kW)	586
Fixed O&M ($/kW-yr)	12.7
Firm Gas Cost ($/kW-yr)	22.7
Start Cost - maintenance ($/Start)	11,147
Heat Rate (MMBtu/MWh)	10.9
Transmission Cost ($/MW-Yr)	N/A
Nominal O&M Cost Escalation	2%
Summer Net Capacity (MW)	159
Winter Net Capacity (MW)	179

5.5. Financial Assumptions

Table 13 lists the inputs used to compute capital revenue requirements in this analysis.

Table 13 – Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.02%
Cost of Equity	10.0%
Tax Rate	24.95%
Property Tax Rate	0.15%
Insurance Rate	0.0254%
WACC (After-Tax)	6.75%