**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

| | | |
|---|---|---|
| **ELECTRONIC 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY** | **)<br>)<br>)<br>)** | **CASE NO. 2021-00393** |

**RESPONSE OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY AND**
**KENTUCKY UTILITIES COMPANY TO**
**JOINT INTERVENORS**
**SUPPLEMENTAL REQUESTS FOR INFORMATION**
**DATED MARCH 4, 2022**

**FILED: MARCH 25, 2022**

## VERIFICATION

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Daniel K. Arbough
**Daniel K. Arbough**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

## VERIFICATION

**COMMONWEALTH OF KENTUCKY )**

**COUNTY OF JEFFERSON )**

The undersigned, **Christopher D. Balmer**, being duly sworn, deposes and says that he is Director – Transmission Strategy and Planning for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Chris D Balmer

**Christopher D. Balmer**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

**VERIFICATION**

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **John Bevington**, being duly sworn, deposes and says that he is Director – Business and Economic Development for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John E. Bevington
**John Bevington**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

## VERIFICATION

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

**Robert M. Conroy**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

## VERIFICATION

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **Michael P. Drake**, being duly sworn, deposes and says that he is Director – Generation Services for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

**Michael P. Drake**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2022.

Notary Public

Notary Public ID. No. 603967

My Commission Expires:

July 11, 2022

## VERIFICATION

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **Eileen L. Saunders**, being duly sworn, deposes and says that she is Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Eileen L Saunders

**Eileen L. Saunders**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

**VERIFICATION**

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

**David S. Sinclair**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

## 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 responses for which he is identified as the witness, and 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 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

**VERIFICATION**

**COMMONWEALTH OF KENTUCKY )**
**)**
**COUNTY OF JEFFERSON )**

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

JK Wolfe

**John K. Wolfe**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

**July 11, 2022**

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.1**

**Responding Witness: Stuart A. Wilson**

Q-2.1. Please refer to the Companies' response to Joint Intervenors' Question 1.4(b). [The Companies have been using PROSYM for production cost modeling for decades and many tools supporting PROSYM have been developed to support its efficient use. Even though Plexos is capable of production cost modeling, it will take time to build the same level of analytical robustness and efficiency as PROSYM.]

a. Please identify and fully explain the function of each "tool supporting PROSYM."

b. Please clarify what is meant by the statement that it will "take time to build the same level of analytical robustness and efficiency as PROSYM"?

c. Are the Companies developing the resources or tools necessary to use Plexos for production cost modeling?

   i. If so, please state approximately when that effort started (e.g., month and year), the approximate time expected to project completion, and an estimate of the work hours involved.

   ii. If not, please explain why not.

d. Does any other group within the Companies currently use PLEXOS, e.g., for generation scheduling or market price forecasting?

e. How do the Companies intend to use PLEXOS in (i) future IRP filings and (ii) future certificate of need filings (e.g., which years would be modeled, what modules of PLEXOS would be used, etc.)?

A-2.1.

a. Tools supporting PROSYM include any file supporting the development of PROSYM input files or processing of output files. This includes numerous spreadsheets, along with custom reporting queries developed in an Access database called Reporter, and the ability to create and read cases in bulk with a SAS program called Case Developer. Examples of these files can be found in the following file paths of the response to JI 1-3:
   - \0283_2021IRP\ResourceAssessment\ReferenceCase
   - \2022Plan

b. The tools supporting PROSYM were developed to serve business needs over many years. Replicating the efficiency of existing tools requires careful planning and testing. Furthermore, PLEXOS was acquired primarily to support the Companies' expansion planning efforts, so work to date has prioritized utilization of PLEXOS as an expansion planning tool.

c. The Companies have been testing the production cost capabilities of PLEXOS since January 2021 in parallel with use of PROSYM. The Companies have not estimated work hours associated with this evaluation and have not yet confirmed if or when PLEXOS will be appropriate to serve the Companies' production cost modeling needs.

d. No.

e. The Companies intend to use PLEXOS for expansion planning in future IRP and CPCN filings. The Companies have not developed plans for any future filings, but time periods for IRP filings will likely consider part or all of the 15-year IRP planning horizon and CPCN filings will likely consider part or all of a 30-year planning horizon.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.2**

**Responding Witness: Stuart A. Wilson**

Q-2.2. Refer to the Companies' response to Joint Intervenors Request 1.19(c), including the attached document, titled "Analysis of Generating Unit Retirement Years" (October 2020).

a. The attached document states on page 10: "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." Did the Companies calculate the NPVRR impact of retiring MC2 in any year(s) earlier than 2028?

   i. If so, please provide each NPVRR impact calculation for retirement years earlier than 2028, including workpapers in native format with formulas intact.

   ii. If not, please explain in full why the Companies did not calculate the NPVRR impact of retiring MC2 in any years earlier than 2028.

b. Refer to Table 8 in the attached document, providing "Stay- Open Costs" for Mill Creek 2 and Brown 3 for the years 2026 through 2034. Please provide the Stay-Open Costs for each unit in the years 2022–2025 (with O&M and annual costs provided separately, as in Table 8).

c. For each of the last five years, please provide the following information for each of Mill Creek, Ghent, and Tremble County:

   i. The total amount of fly ash created (tons per year);
   ii. The total amount of gypsum created (tons per year);
   iii. The total number of tons of fly ash sold from each plant; and
   iv. The total number of tons of gypsum sold from each plant.

A-2.2.

a. No. In their 2020 rate cases, the Companies proposed depreciation rates based upon a 2028 MC2 retirement date, which was an earlier retirement date than the Companies had previously used for MC2 (2034).[1] The rate case parties entered a stipulation that included a revenue adjustment for the difference in depreciation expense between retaining a 2034 MC2 retirement date versus retiring MC2 in 2028;[2] at no point did a party suggest using an earlier retirement date. The Commission approved the stipulation in relevant part while the Companies were completing their IRP analysis;[3] thus, the Companies' IRP reflects the 2028 MC2 retirement assumption implicit in the rate case stipulation.

b. See below.

| **Total Stay-Open Costs ($M)** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|
| MC2 – major maintenance | 0.0 | 0.0 | 0.0 | 0.0 |
| MC2 – annual | 22.1 | 17.5 | 29.6 | 20.7 |
| BR3 – major maintenance | 0.0 | 0.0 | 0.0 | 0.0 |
| BR3 – annual | 30.7 | 30.7 | 36.7 | 38.3 |

c. The requested data is shown in the tables below.

i. **Fly Ash Produced (thousand tons)**

| **Year** | **Mill Creek** | **Ghent** | **Trimble County** |
|---|---|---|---|
| 2017 | 310 | 400 | 230 |
| 2018 | 293 | 357 | 218 |
| 2019 | 276 | 328 | 224 |
| 2020 | 242 | 314 | 246 |
| 2021 | 308 | 359 | 259 |

ii. **Gypsum Produced (thousand tons)**

| **Year** | **Mill Creek** | **Ghent** | **Trimble County** |
|---|---|---|---|
| 2017 | 693 | 883 | 426 |
| 2018 | 710 | 926 | 419 |
| 2019 | 595 | 794 | 453 |
| 2020 | 504 | 741 | 470 |
| 2021 | 510 | 726 | 463 |

[1] *See, e.g.*, Case Nos. 2020-00349 and 2020-00350, Direct Testimony of Lonnie E. Bellar at Exh. LEB-2 and Direct Testimony of Christopher M. Garrett at 27-28 (Nov. 25, 2020).
[2] Case Nos. 2020-00349 and 2020-00350, Order Appx. A at 7, para. 2.3 (Ky. PSC June 30, 2021).
[3] Case Nos. 2020-00349 and 2020-00350, Order (Ky. PSC June 30, 2021).

iii. **Fly Ash Sold (thousand tons)**

| Year | Mill Creek | Ghent | Trimble County |
|---|---|---|---|
| 2017 | 203 | 15 | 201 |
| 2018 | 198 | 21 | 170 |
| 2019 | 213 | 27 | 172 |
| 2020 | 174 | 29 | 192 |
| 2021 | 211 | 13 | 187 |

iv. **Gypsum Sold (thousand tons)**

| Year | Mill Creek | Ghent | Trimble County |
|---|---|---|---|
| 2017 | 504 | 475 | 177 |
| 2018 | 512 | 463 | 121 |
| 2019 | 516 | 577 | 189 |
| 2020 | 436 | 649 | 159 |
| 2021 | 518 | 746 | 307 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.3**

**Responding Witness: Daniel K. Arbough / Stuart A. Wilson**

Q-2.3. Refer to the Companies' response to Joint Intervenors' Request 1.22(a), which states in part, "These costs reflect the stay-open capital used in the 2021 IRP. The costs do not include all capital items in the Companies' current Business Plan."

a. Please provide the Companies' current Business Plan.

b. Please identify each capital item included in the current Business Plan but not used in the 2021 IRP.

c. Please provide a workbook with each capital item identified in response to subpart b, including a description for each.

d. For each of the Companies' thermal resources, please explain how the forecasted capital expenditures for thermal resources in the Companies' current Business Plan differ from those used in the IRP modeling for each of the Companies' thermal resources

A-2.3.

a. The Companies' reference to the "current Business Plan" quoted in this request is a reference to the Companies' 2021 Business Plan. Attached are the portions of the 2021 Business Plan that were relevant to developing the 2021 IRP.

b. Capital costs that will be incurred regardless of whether a unit continues operation were excluded from stay-open costs. Generation costs in the attachment to part a. were utilized in the IRP. Costs, other than Generation, included on pages 39 and 40 of the attachment to part a. were excluded from the IRP. The mechanism investments included on page 41 of the attachment to part a. were excluded from the IRP.

c. See the response to part (b).

d. See the response to part (b). Forecasted expenditures used in the 2021 IRP were based on Stay-Open costs, which consist only of costs necessary to keep a unit online. Stay-Open costs exclude expenses that will be incurred regardless of a unit's operational status.

# Generation
# LG&E and KU Utilities
# 2021 Operating Plan

**September 2020**

# Table of Contents

# Plan Highlights

- Major investment and integration of environmental compliance – Coal Combustion Residuals (CCR), pond closures and Effluent water Limitation Guidelines (ELG).
- Generation forecast assumes continued trend of high Natural Gas Combined Cycle (NGCC) production levels based on current projections for gas prices over the five year plan.
- Increased resource requirements to meet and maintain compliance with incremental regulatory requirements – ELG staffing will begin in 2023.
- No generation capacity additions are in the plan through 2025.

# Major Operational Assumptions

- Mill Creek 2 offline from April through October starting in 2021 and continuing through 2024 to comply with Louisville Metro Air Pollution Control District agreement.

- Retirement of Mill Creek 1: 12/31/2024

- The next turbine overhauls by unit are as follows:
  - 2020: Ghent 4
  - 2021: Ghent 1
  - 2022: Mill Creek 4
  - 2023: Trimble County 2 (Generator)
  - 2024: Cane Run 7 (CT1, CT2, and ST HP-IP)
  - 2025: Trimble County 1

- Demolition Timing:
  - Completed:
    - Paddy's Run Coal Plant (2017)
    - Green River Coal Plant (February 2020)
    - Pineville Coal Plant (2019)
    - Tyrone Coal Plant (July 2020)
  - Cane Run Coal Plant completion expected 3rd quarter 2020
  - Canal Station completion expected 4th quarter 2021

# Major Financial Assumptions

- Base rate case will be filed in the fourth quarter of 2020 for test year beginning July 1, 2021 through June 30, 2022. Base year will be March 1, 2020 through February 28, 2021.

- Outage normalization:
    - Current regulatory treatment is based on a five year historical average through June 2021.
    - Assumes regulatory treatment is based on an eight year average (four year historical and four years forward looking 2017-2024)
    - Assume amortization of regulatory assets or liabilities will be over a six year period for the remaining balance on the 2016 case and over an eight year period for the balance on the 2018 case .

- Labor budget built on current work force plan recommendations. Assumptions include an anticipated retirement savings based on actuarial calculations developed by Towers Watson and a wage increase for current employees on average of 3% per year.

- Supplemental contractor work force includes on average a 3.2% escalation in costs based on anticipated increase in contracts expected be awarded in 2021.

- As currently drafted, the Affordable Clean Energy (ACE) Rule would have insignificant cost impacts; however, no costs have been included in the 2021 business plan.

- The plan does not include potential ongoing expenses related to COVID-19.

# Major Assumptions – Combustion Turbines

- Combustion turbine (CT) outages in the plan:
  - The second set of Trimble County CT hot gas path inspections are in progress with the remaining units scheduled as follows:
    - Unit 9 in 2020
    - Unit 8 in 2021
    - Unit 10 in 2024
  - The third hot gas path inspection will commence on TC Unit 5 in the fall of 2020 and will include a rotor inspection.
  - A hot gas path inspection on Paddy's Run 13 is scheduled to commence in 2025.
  - E.W. Brown C inspections by unit are as follows:
    - Unit 7 in 2021
    - Unit 8 in 2022
    - Unit 9 in 2025

- Funding for enhanced in line inspections for gas transmission included in fuel costs for E.W. Brown (2021), Cane Run 7 (2022), Trimble County (2025) and Paddy's Run 12 (2025).

- E.W. Brown 6 and 7 Long-Term Services Agreement (LTSA) is in place.

- The CT component outages for Cane Run 7 are a Hot Gas Path Inspection (HGPI) Spring 2020, Combustion Inspection Spring 2022, and a major in 2024 (HGPI and turbine overhaul).
  - Cane Run 7 CT's are covered under a signed Long Term Program Contract (LTPC).

# Major Assumptions – Water Treatment

- Process water systems (PWS) (Phys-chem for Mercury, Arsenic, metals) included on the 2016 ECR plan for all four coal-fired plants:
    - Mill Creek – In-service November 2019
    - Trimble County – In-service October 2019
    - Ghent – April 2020
    - E.W. Brown – May 2020
- All PWS labor and non labor costs for operating and maintaining process water systems are in base rates.
- Effluent Limitation Guidelines (ELG), primarily for Mercury, Selenium, and Nitrate reductions have projected capital spend in 2020-2024. Trimble County has an anticipated in service date of November 2023 while the anticipated in service date for Mill Creek and Ghent November 2024.
- ELG at E.W. Brown is included in the plan as a sensitivity due to less volume resulting in cycling up chlorides and closed loop on WFGD.
- ELG plans include a diffuser at Ghent and Mill Creek (both in-service 2021), and a bottom ash sluice water recirculation system at Ghent (in-service 2023).
- An ECR filing for ELG was submitted in April 2020 seeking recovery of ELG costs, both capital and operating expense. ECR approval granted October 2020 to support award of EPC in 4Q, 2020.
- ELG operating expenses included in the plan align with the ECR filing.

# Major Assumptions – Coal Combustion Residuals (CCR's)

- EPA finalized the CCR rule on December 19, 2014 (published in the Federal Register on April 17, 2015).
  - Expect all CCR impoundments to stop receiving sluiced CCR by October 2020 due to trigger of groundwater criteria. (The Remand Rule Phase I Part I to the CCR Rule provided 18 months of relief for impoundment to stop receiving sluiced CCR and start the closure process to October 2020.)
  - Congress passed and the President signed the Water Infrastructure Improvements for the Nation Act (WIIN Act) on December 16, 2016. The WIIN Act is the first step to allow for the implementation of the federal CCR Rule through a state or federal based permit program.
  - All CCR impoundment closures, including non process water ponds and PWS Phys-chem water treatment facilities, were included in the approved 2016 ECR filing.

- CCR Impoundment Closures under the CCR rule by year are as follows:
  - Completed Closures
    - 2017 - Mill Creek Emergency Pond
    - 2018 - Mill Creek Clearwell and Construction Runoff Pond , Green River SO2 Pond and Main Ash Pond
    - 2019 - Green River ATB #2, Pineville Ash Pond, Tyrone Ash Pond, Mill Creek Dead Storage Pond, Ghent Reclaim Pond and Gypsum Stack (Phase I of II)
    - 2020 - E.W. Brown Main Ash Pond (landfill partial Phase II and entire Phase III)
  - 2020: Ghent Gypsum Stack (Phase II of II) and Mill Creek Ash Pond
  - 2021: Ghent ATB #1,Ghent Secondary Pond, and E.W. Brown Auxiliary Pond.
  - 2023: Trimble County GSP and Ghent ATB#2 .
  - 2024: Trimble County BAP.
    - NOTE: Given recent updates to the CCR Rule, the 5-year deadline is no later than August 2025.

- Each pond will be retired from the property accounting ARO perspective in the year it is closed.

# Major Assumptions – CCR (continued)

- CCR Well Installation and Monitoring
  - The installation of wells at each of the CCR-regulated units and the initial eight rounds of background monitoring required by the CCR Rule was completed in February 2019 under the direction of Project Engineering.
  - Ongoing CCR well sampling, additional CCR-related well installations, and monitoring cost post-trigger for 30-year minimum are managed and covered by Generation Services projects.
  - Cane Run well monitoring is included in the Generation Services budget as a non-ECR project.
  - Well installation and monitoring costs for Green River, Pineville, and Tyrone are not included in the plan.
- Trimble County Treatment, Transport, and Landfill
  - The treatment system was placed into service in June, 2019.
  - The transport system was placed into service in January, 2020.
  - The contracted in-service date for Landfill Phase 1A is projected to be 4Q, 2021 to account for change of conditions and extensive rainfall in 2018 and 2019.
    - — All permits required to allow landfill construction have been received.
    - — While no lawsuits exist as of September 2020, litigation of permit remains possible; however, construction will continue as planned unless court issues a stay of the permit.
- The CCR impoundment closure projects assume that existing CCR materials from each plant can be beneficially used to construct the designed contour in each pond similar to that done at Cane Run. If that is not allowed by rule, the estimated cost of having to instead procure off-site fill material is an additional $200M.

# 2020-2025 Capital Expenditures
# ($000)

| Item | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| CT Major | $ 11,220 | $ 39,605 | $ 4,110 | $ - | $ 8,971 | $ 46,183 |
| Coal Major | 40,808 | 39,803 | 29,247 | 1,394 | 3,884 | 35,710 |
| Cane Run 7 Major | 24,036 | - | 9,289 | - | 29,901 | - |
| Non-Major Outage | 31,732 | 53,826 | 34,491 | 73,954 | 66,865 | 43,799 |
| Reliability | 41,992 | 67,761 | 23,020 | 37,767 | 40,215 | 23,743 |
| OT Security | - | 1,585 | 379 | - | - | - |
| ECR Mechanism | 12,077 | 1,126 | 186 | 197 | 197 | 197 |
| All Other | 7,244 | 6,266 | 1,055 | 3,156 | 4,313 | 2,289 |
| **Total Capital** | **$ 169,110** | **$ 209,972** | **$ 101,775** | **$ 116,468** | **$ 154,346** | **$ 151,922** |
| **2020 Plan** | **$ 149,385** | **$ 220,091** | **$ 106,210** | **$ 121,099** | **$ 166,115** | |
| **Change** | **$ (19,725)** | **$ 10,119** | **$ 4,435** | **$ 4,631** | **$ 11,769** | **$ (151,922)** |

**Case No. 2021-00393**
**Attachment to Response to JI-2 Question No. 3(a)**
**10 of 41**
**Arbough/Wilson**

# 2020-2025 Annual O&M Expenses ($000)

| Item | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Non-Outage: | | | | | | |
| Labor | $ 80,817 | $ 87,900 | $ 90,052 | $ 89,972 | $ 90,850 | $ 91,747 |
| Supplemental Contractors | 22,290 | 26,545 | 29,190 | 30,827 | 31,562 | 32,880 |
| Plant Maintenance | 51,611 | 60,164 | 63,848 | 61,372 | 56,826 | 55,409 |
| Plant Operations | 12,311 | 15,890 | 19,924 | 20,274 | 20,828 | 20,671 |
| Variable Plant O&M | 21,822 | 28,229 | 34,997 | 36,071 | 37,780 | 37,778 |
| Subtotal Non-Outage | $ 188,850 | $ 218,728 | $ 238,012 | $ 238,516 | $ 237,846 | $ 238,485 |
| Outage: | | | | | | |
| Labor | $ 3,217 | $ 3,401 | $ 2,730 | $ 2,696 | $ 2,937 | $ 3,211 |
| Supplemental Contractors | 2,204 | 1,833 | 1,444 | 1,607 | 1,370 | 1,597 |
| Non Labor | 27,100 | 38,195 | 48,457 | 47,891 | 48,912 | 47,772 |
| Subtotal Outage | $ 32,520 | $ 43,428 | $ 52,631 | $ 52,194 | $ 53,219 | $ 52,580 |
| **Base Rate Recovery** | **$ 221,370** | **$ 262,156** | **$ 290,643** | **$ 290,709** | **$ 291,065** | **$ 291,065** |
| ECR Mechanism O&M: | | | | | | |
| Labor | $ 3,334 | $ 1,680 | $ 381 | $ 510 | $ 891 | $ 1,134 |
| Supplemental Contractors | 4,637 | 3,546 | 1,801 | 3,100 | 4,913 | 6,201 |
| Non Labor | 13,605 | 3,426 | (6,554) | (4,551) | (321) | 3,151 |
| **ECR Mechanism Recovery** | **$ 21,575** | **$ 8,651** | **$ (4,371)** | **$ (941)** | **$ 5,482** | **$ 10,486** |
| **Total O&M - GAAP View** | **$ 242,945** | **$ 270,807** | **$ 286,272** | **$ 289,768** | **$ 296,547** | **$ 301,551** |

Note - ECR Termination: 2021 - $13,446k, 2022 - $26,079k, 2023 - $28,146k, 2024 - $30,142k, 2025 - $30,454k

# Employee Headcount by Department

| Department | Forecast 2020 | Plan 2021 | Plan 2022 | Plan 2023 | Plan 2024 | Plan 2025 |
|---|---|---|---|---|---|---|
| Mill Creek | 204 | 215 | 214 | 207 | 201 | 201 |
| Trimble County | 174 | 183 | 182 | 183 | 184 | 184 |
| Cane Run/Ohio Falls | 49 | 52 | 52 | 52 | 52 | 52 |
| Ghent | 202 | 214 | 212 | 212 | 214 | 215 |
| Brown | 113 | 116 | 113 | 112 | 110 | 108 |
| Generation Services | 55 | 60 | 60 | 60 | 60 | 60 |
| Commercial Ops | 44 | 45 | 44 | 44 | 44 | 44 |
| Other Generation | 4 | 5 | 4 | 4 | 4 | 4 |
| CO-OPS / Interns | 24 | 42 | 42 | 38 | 38 | 38 |
| Total | 869 | 932 | 923 | 912 | 907 | 906 |

Total Employee Workforce

| | | | | | | |
|---|---|---|---|---|---|---|
| 2021BP | 869 | 932 | 923 | 912 | 907 | 906 |
| Prior Plan | 938 | 940 | 937 | 939 | 941 | - |
| Change from Prior Plan | 69 | 8 | 14 | 27 | 34 | (906) |

2020 numbers are August actuals.
Plan years are based on average headcount.
The increase from 2020 to 2021 due to current open employee positions.

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# Supplemental Contractor Headcount by Department

| Department | Forecast 2020 | Plan 2021 | Plan 2022 | Plan 2023 | Plan 2024 | Plan 2025 |
|---|---|---|---|---|---|---|
| Mill Creek | 132 | 134 | 134 | 135 | 138 | 141 |
| Trimble County | 112 | 110 | 110 | 118 | 122 | 118 |
| Cane Run/Ohio Falls | 5 | 6 | 6 | 6 | 6 | 6 |
| Ghent | 124 | 129 | 129 | 129 | 133 | 136 |
| Brown | 38 | 42 | 42 | 43 | 44 | 46 |
| Commercial Ops | 14 | 14 | 14 | 14 | 14 | 14 |
| Generation Services | 23 | 22 | 22 | 22 | 22 | 22 |
| | | | | | | |
| Total | 448 | 456 | 456 | 466 | 478 | 483 |
| Total Contractor Workforce | | | | | | |
| 2021BP | 448 | 456 | 456 | 466 | 478 | 483 |
| Prior Plan | 468 | 471 | 471 | 472 | 480 | |
| Change from Prior Plan | 20 | 15 | 15 | 6 | 2 | (483) |

-2020 numbers are August actuals.
-Plan years are based on average headcount.
-The increase from 2020 to 2021 due to current open positions.
-Increase at Trimble County in 2023 driven by landfill operations contractors (9) upon completion of utilizing plant material for pond closures as well as ELG contractors (7). Increase in 2023 offset by reductions in late 2024 and 2025 of maintenance contractors (8).
-ELG contractors at Ghent starting in 2023 (7) and Mill Creek in 2024 (6).

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# 2020-2025 Supplemental Contractors Non-Outage Base ($000)

| Supplemental Contractors | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Fuel and Ash Handling Equipment | $ 6,920 | $ 6,833 | $ 7,091 | $ 7,342 | $ 7,617 | $ 7,861 |
| Buildings and Grounds | 4,678 | 5,493 | 5,628 | 5,828 | 5,658 | 5,868 |
| Boiler Systems | 2,487 | 4,136 | 4,224 | 4,397 | 3,788 | 4,140 |
| Process Water | 2,039 | 2,236 | 2,291 | 2,362 | 2,421 | 2,519 |
| Plant Operations | 2,302 | 2,646 | 3,419 | 4,095 | 4,829 | 5,011 |
| Environmental | 1,163 | 2,051 | 3,034 | 3,193 | 3,326 | 3,532 |
| CCR Disposal | 1,755 | 1,713 | 2,009 | 2,065 | 2,112 | 2,145 |
| Cooling Water Systems | 426 | 464 | 475 | 484 | 479 | 481 |
| Turbine/Generator Systems | 189 | 165 | 179 | 184 | 184 | 177 |
| Other | 1,916 | 2,692 | 2,770 | 2,857 | 2,944 | 3,038 |
| Total Supplemental Contractors (100%) | $ 23,875 | $ 28,430 | $ 31,122 | $ 32,807 | $ 33,358 | $ 34,774 |
| Trimble County Partner | $ (1,585) | $ (1,885) | $ (1,931) | $ (1,980) | $ (1,796) | $ (1,893) |
| Total Supplemental Contractors Net | $ 22,290 | $ 26,545 | $ 29,190 | $ 30,827 | $ 31,562 | $ 32,880 |

# 2020-2025 Plant Maintenance
# Non-Outage Base
# ($000)

| Maintenance | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Boiler Systems | $ 9,434 | $ 11,115 | $ 10,989 | $ 10,667 | $ 9,570 | $ 8,771 |
| Turbine/Generator Systems | 3,926 | 5,338 | 5,340 | 5,438 | 5,278 | 5,264 |
| Cooling Water Systems | 3,293 | 4,176 | 3,827 | 4,167 | 3,715 | 3,953 |
| Fuel and Ash Handling Equipment | 6,164 | 7,627 | 7,400 | 6,499 | 5,799 | 6,060 |
| Landfill and CCRT | 1,393 | 2,970 | 4,504 | 4,198 | 4,126 | 4,175 |
| Buildings and Grounds | 9,982 | 8,178 | 7,953 | 7,879 | 7,427 | 6,887 |
| Electrical Systems | 857 | 842 | 852 | 857 | 865 | 874 |
| Flue Gas Desulfurization (FGD) | 2,805 | 3,049 | 3,537 | 3,583 | 3,462 | 3,016 |
| Limestone Systems | 1,681 | 3,336 | 2,737 | 2,549 | 2,531 | 2,789 |
| Tools and Consumables | 2,461 | 2,038 | 2,038 | 2,039 | 2,047 | 2,064 |
| Process Water Systems | 821 | 1,769 | 1,817 | 1,865 | 1,912 | 1,951 |
| Compressed Air Systems | 1,240 | 1,247 | 1,247 | 1,141 | 1,334 | 1,340 |
| Computer/Monitoring/Controls Systems | 3,356 | 3,221 | 3,274 | 3,322 | 3,141 | 3,185 |
| Inspections | 744 | 986 | 784 | 606 | 582 | 529 |
| Obsolete Inventory | 453 | 996 | 998 | 760 | 765 | 774 |
| Precipitator | 402 | 161 | 168 | 168 | 169 | 170 |
| Selective Catalytic Reduction (SCR) systems | 1,078 | 807 | 893 | 887 | 854 | 907 |
| SO3 Mitigation systems | 16 | 181 | 327 | 327 | 329 | 332 |
| Pulse Jet Fabric Filter (PJFF) systems | 51 | 510 | 1,075 | 891 | 888 | 739 |
| Brown Regulatory Assets | 824 | 412 | - | - | - | - |
| Other Maintenance | 3,467 | 4,080 | 6,946 | 6,323 | 4,430 | 4,117 |
| Total Maintenance (100%) | $ 54,449 | $ 63,039 | $ 66,705 | $ 64,166 | $ 59,221 | $ 57,895 |
| Trimble County Partner | $ (2,839) | $ (2,875) | $ (2,857) | $ (2,794) | $ (2,396) | $ (2,486) |
| Total Maintenance Net | $ 51,611 | $ 60,164 | $ 63,848 | $ 61,372 | $ 56,826 | $ 55,409 |

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# 2020-2025 Plant Operations Non-Outage Base ($000)

| Operations | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Chemicals/Gases/Diesel | $ 4,212 | $ 5,158 | $ 4,930 | $ 4,701 | $ 4,779 | $ 4,788 |
| Administrative and General Supplies | 2,131 | 1,823 | 1,847 | 1,872 | 1,889 | 1,908 |
| Health and Safety | 2,953 | 1,798 | 1,832 | 1,819 | 1,832 | 1,850 |
| Fuel Handling Equipment | 1,559 | 1,710 | 1,763 | 1,808 | 1,827 | 1,851 |
| Tools and Consumables | 1,124 | 1,732 | 1,760 | 1,777 | 1,744 | 1,577 |
| Water and Water Treatment | 1,380 | 1,321 | 1,332 | 1,315 | 1,309 | 1,325 |
| HydroElectric Facilities | 836 | 993 | 1,008 | 1,023 | 1,039 | 1,054 |
| Combustion Turbine Facilities | 740 | 1,214 | 1,331 | 1,189 | 1,277 | 1,196 |
| Environmental | 410 | 800 | 1,082 | 1,044 | 1,040 | 1,018 |
| Training and Development | 326 | 641 | 644 | 646 | 649 | 650 |
| OT IT Security | - | 496 | 991 | 991 | 991 | 991 |
| Refined Coal | (5,234) | (2,487) | - | - | - | - |
| Other Operations | 2,915 | 1,745 | 2,735 | 3,442 | 3,857 | 3,916 |
| Total Plant Operations (100%) | $ 13,352 | $ 16,944 | $ 21,256 | $ 21,628 | $ 22,233 | $ 22,126 |
| Trimble County Partner | $ (1,042) | $ (1,054) | $ (1,332) | $ (1,354) | $ (1,404) | $ (1,456) |
| Total Operations Net | $ 12,311 | $ 15,890 | $ 19,924 | $ 20,274 | $ 20,828 | $ 20,671 |

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# 2020-2025 Variable Plant O&M Expense
# Non-Outage Base
# ($000)

| Item | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Scrubber Reactant Ex | $15,031 | $13,121 | $13,350 | $13,821 | $14,472 | $14,262 |
| NOx Reduction Reagent | 4,051 | 4,262 | 4,443 | 4,573 | 4,934 | 4,932 |
| Liquid Injection Reagent | 2,003 | 2,786 | 3,979 | 4,000 | 4,525 | 4,626 |
| Sorbent Reactant | 1,868 | 7,286 | 11,935 | 12,240 | 12,654 | 12,729 |
| Process Water Chemicals | 1,122 | 1,760 | 1,745 | 1,692 | 1,763 | 1,781 |
| Activated Carbon | - | 738 | 1,431 | 1,524 | 1,506 | 1,441 |
| Other Waste Disposal | 81 | 312 | 514 | 528 | 542 | 554 |
| Total Variable Plant O&M Expenses (100%) | $24,155 | $30,264 | $37,398 | $38,378 | $40,396 | $40,326 |
| Trimble County Partner | (2,333) | (2,035) | (2,401) | (2,306) | (2,616) | (2,548) |
| Total Variable Plant O&M Expenses Net | $ 21,822 | $ 28,229 | $ 34,997 | $ 36,071 | $ 37,780 | $ 37,778 |

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# 2020-2025 Outage Expense
# ($000)

| Outages | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Coal Fired Units | $37,536 | $46,882 | $36,262 | $33,602 | $35,617 | $39,263 |
| Combustion Turbines | $9,709 | $4,207 | $6,594 | $2,763 | $16,765 | $3,608 |
| **Total Outage** | **$47,245** | **$51,089** | **$42,856** | **$36,365** | **$52,382** | **$42,871** |
| Outage Normalization | ($15,404) | ($11,792) | $2,192 | $8,246 | ($6,747) | $2,126 |
| **Outage Normalized** | **$31,841** | **$39,297** | **$45,048** | **$44,611** | **$45,636** | **$44,997** |
| Outage Regulatory Asset Amortization 2016 Case | $679 | $1,087 | $1,495 | $1,495 | $1,495 | $1,495 |
| Outage Regulatory Asset Amortization 2018 Case | $0 | $3,044 | $6,088 | $6,088 | $6,088 | $6,088 |
| **Outage Regulatory Asset Amortization** | **$679** | **$4,131** | **$7,583** | **$7,583** | **$7,583** | **$7,583** |
| **2021 Business Plan Outage Expense** | **$32,520** | **$43,428** | **$52,631** | **$52,194** | **$53,219** | **$52,580** |

# 2020-2025 Mechanism O&M Expense
# ($000)

| Item | 2020 Forecast | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Labor | $3,441 | $1,791 | $508 | $680 | $1,106 | $1,355 |
| Supplemental Contractor | 4,968 | 4,086 | 2,325 | 3,985 | 5,981 | 7,309 |
| ECR ELG Chemicals | - | - | - | 590 | 3,024 | 5,015 |
| ECR ELG Maintenance | - | - | - | 546 | 2,231 | 3,458 |
| ECR Landfill Operations | 645 | 238 | - | - | - | - |
| ECR Landfill Maintenance | 5,675 | 3,151 | 1,751 | 3,527 | 3,541 | 3,666 |
| ECR Fly Ash Disposal - Beneficial Reuse | (5,332) | (5,946) | (5,846) | (6,075) | (5,720) | (5,561) |
| ECR Other Waste Disposal - Beneficial Reuse | (3,339) | (2,675) | (2,869) | (2,865) | (2,864) | (2,851) |
| ECR CCP System Maintenance | 176 | 346 | 406 | 412 | 418 | 428 |
| ECR Activated Carbon | 1,435 | 698 | - | - | - | - |
| ECR Liquid Injection - Reagent | 1,611 | 1,109 | - | - | - | - |
| ECR Nox Reduction Reagent | 294 | 127 | - | - | - | - |
| ECR Sorbent Reactant - Reagent | 10,278 | 5,318 | - | - | - | - |
| ECR Baghouse Maintenance | 654 | 530 | - | - | - | - |
| ECR Maintenance-FGDs | 1,043 | 485 | - | - | - | - |
| ECR Maintenance Of SCR/NOx Reduction Equip | 68 | 56 | - | - | - | - |
| ECR Sorbent Injection Operation | 228 | 51 | - | - | - | - |
| ECR Sorbent Injection Maintenance | 391 | 145 | - | - | - | - |
| ECR SO2 Emission Allowances | 1 | - | - | - | - | - |
| Total ECR Mechanism | $22,237 | $9,509 | ($3,724) | $801 | $7,718 | $12,818 |
| Trimble County Partner | (662) | (858) | (647) | (1,742) | (2,236) | (2,332) |
| Total ECR Mechanism Net | $ 21,575 | $ 8,651 | $ (4,371) | $ (941) | $ 5,482 | $ 10,486 |



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# O&M Annual Expense Reconciliation ($000)

| | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|
| **2021 Business Plan** | **$ 270,807** | **$ 286,272** | **$ 289,768** | **$ 296,547** | **$ 301,551** |
| **2020 Business Plan** | **$ 283,460** | **$ 297,254** | **$ 303,703** | **$ 314,626** | **$ 319,706** |
| **Change** | **$ 12,654** | **$ 10,982** | **$ 13,935** | **$ 18,079** | **$ 18,155** |
| **<u>Drivers:</u>** | | | | | |
| Outage | | | | | |
| Outage O&M | $ (6,940) | $ 451 | $ 573 | $ (278) | $ 10,188 |
| Outage Normalization | 3,917 | (908) | (1,018) | (221) | (10,244) |
| Outage Regulatory Asset Amortization 2016 Case | 149 | 19 | 19 | 19 | 19 |
| Outage Regulatory Asset Amortization 2018 Case | 1,249 | 352 | 352 | 352 | 352 |
| **Subtotal Outage** | **$ (1,625)** | **$ (86)** | **$ (75)** | **$ (129)** | **$ 314** |
| Non Outage: | | | | | |
| Labor | $ 1,052 | $ 1,221 | $ 3,296 | $ 4,213 | $ 5,025 |
| Retirement Savings | 740 | 1,827 | 2,884 | 3,885 | 4,859 |
| Supplemental Contractors | 2,324 | 2,320 | 553 | (729) | (2,294) |
| Non Labor: | | | | | |
| Refined Coal | 2,270 | 0 | 0 | 0 | 0 |
| Reactants and Reagents | 3,891 | 5,840 | 6,064 | 6,549 | 5,326 |
| Process Water Systems | 1,123 | 1,240 | 1,407 | 1,511 | 1,461 |
| Beneficial Reuse | 2,075 | 1,991 | 2,229 | 1,847 | 1,536 |
| Maintenance and Overhauls | (944) | (5,291) | (2,441) | 2,331 | 5,832 |
| Mill Creek 2 APCD Agreement | 522 | 454 | 404 | 1,038 | 229 |
| Mill Creek 1 Retirement | | | 91 | 197 | 1,106 |
| TC Landfill Ops and Maintenance | 2,639 | 2,557 | 1,380 | 1,407 | 1,440 |
| GH Landfill Ops and Maintenance | (988) | (206) | (1,214) | (2,188) | (2,254) |
| Effluent Water - ELG | | 100 | 356 | (747) | (3,841) |
| OT IT Security | (496) | (991) | (991) | (991) | (991) |
| Non Labor Other | 69 | 6 | (8) | (116) | 405 |
| **Subtotal Non Outage** | **$ 14,279** | **$ 11,068** | **$ 14,010** | **$ 18,208** | **$ 17,841** |
| **Total Drivers** | **$ 12,654** | **$ 10,982** | **$ 13,935** | **$ 18,079** | **$ 18,155** |

# Operational Performance

## Key Performance Indicators

| KPI | 2020 Forecast[6] | 2021 Plan | 2022 Plan | 2023 Plan | 2024 Plan | 2025 Plan |
|---|---|---|---|---|---|---|
| Generation (Twh)[1] | 30.27 | 31.26 | 31.44 | 31.36 | 31.41 | 31.30 |
| EAF (Steam) | 84.5% | 84.2% | 86.2% | 86.3% | 85.5% | 86.7% |
| EFOR (Steam) | 4.5% | 4.5% | 4.5% | 4.5% | 4.5% | 4.5% |
| Controllable Cost ($M)[2] | $242.9 | $270.8 | $286.3 | $289.8 | $296.5 | $301.6 |
| Controllable Cost (per Mwh)[2] | $8.03 | $8.66 | $9.11 | $9.24 | $9.44 | $9.63 |
| Cash Cost (per Mwh)[3] | $13.61 | $15.38 | $12.34 | $12.95 | $14.36 | $14.49 |
| Cost Per Mwh [4] | $7.94 | $8.25 | $8.61 | $9.05 | $9.42 | $9.76 |
| Recordable Injuries[5] | 1.03 | 1.10 | 1.09 | 1.08 | 1.07 | 1.07 |
| Days Away/Restricted/Transferred Case Rate (DART) | 0.69 | 0.63 | 0.62 | 0.60 | 0.59 | 0.59 |

[1] Steam Generation includes 75% of Trimble County 1 and 2.

[2] Controllable Costs include Utility O&M and Other Cost of Sales.

[3] Cash cost includes controllable costs plus capital divided by MWH (75% TC)

[4] Five year average - measure is non fuel O&M used in FERC benchmarking and includes all lines of business divided by MWH (75% TC)

[5] The 2020 number represents the August YTD value. Values are without hearing loss.

[6] The 2020 Forecast is based on the 8+4 forecast.

# LKE 2021 Business Plan
# RAC Capital Officer Review*

**August 11, 2020***



PPL companies

* Updates were made to the tables to reflect Final Capital Plan approved based on decisions made in the revi

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# Summary of Changes

**2021 Business Plan**
**Total Capital Variances by Year (in millions)**

| | 2020 | 2021 | 2022 | 2023 | 2024 | Total 20-24 | Total 21-24 |
|---|---|---|---|---|---|---|---|
| Base Capital Variance to Previous Plan | $ (37) | $ (46) | $ 2 | $ 4 | $ (53) | $ (130) | $ (93) |
| Mech Capital Variance to Previous Plan | $ (45) | $ (2) | $ (80) | $ (114) | $ (137) | $ (378) | $ (333) |
| Delta: Lower/(Higher) than '20 BP | **$ (82)** | **$ (48)** | **$ (78)** | **$ (110)** | **$ (189)** | **$ (508)** | **$ (426)** |

Major changes from prior plan:

— Base:
- Gas Transmission Modernization projects previously assumed in the GLT mechanism and revised cost estimates
- Bullitt County timing and scope refinement
- PE projects additions including plant demolitions and new generation in 2024

— Mechanism:
- Full deployment of AMI
- Additional spend related to Effluent Limitation Guidelines
- Partially offset by GLT roll-in

# Key Capital Assumptions – Project Engineering

- Final Effluent Limitation Guidelines(ELG) requires biological treatment for Mercury, Selenium, and Nitrate of FGD waste streams.
  - —Trimble County has an anticipated in-service date in 4Q 2023, while the anticipated in-service date for Mill Creek and Ghent is 4Q 2024.
  - —Other ELG required projects include a diffuser at Ghent and Mill Creek (both in-service 4Q 2021), and a bottom ash transport water recirculation system at Ghent (in-service 4Q 2023).
  - —KPSC approval of the 2020 ECR program expected in September 2020, award of EPC in 4Q, 2020. ELG operating expenses included in the plan align with this filing.
- CCR Impoundment Closures under the CCR rule by year are as follows:
  - — CCR Impoundment Closures Remaining
    - 2020: Ghent Gypsum Stack (Phase II of II) and Mill Creek Ash Pond
    - 2021: Ghent ATB #1,Ghent Secondary Pond, and E.W. Brown Auxiliary Pond.
    - 2023: Trimble County GSP and Ghent ATB#2 .
    - 2024: Trimble County BAP. Subject to a timely acceptable Agreed Order
  - — The anticipated regulatory deadline for all impoundment closures is no later than August 2025.
  - — Each pond will be retired from the property accounting ARO perspective in the year it is closed.
- Trimble County Landfill
  - — The projected in-service date for Landfill Phase 1A shifted to 4Q 2021 due to weather and final geotech quantity impacts.

# Key Capital Assumptions – Project Engineering

- Significant New Generation Projects :
  - 500 MW NGCC for 2029; 2 x 500 MW NGCC for 2034.
- Significant Non-Mech Increases:
  - Ohio Falls Masonry and Trash Racks
  - Ghent DSI
  - Brown Unit 3 ESP Demo; Brown Units 1&2 Demo
  - Cane Run Riverbank Stabilization
  - Solar Share funding transferred to Project Engineering from Customer Service.
- Significant ECR Plan over Plan changes:
  - Trimble Co Phase IB Landfill construction start shifted forward into 2024.
  - ELG program in-service dates shifted out 1 year from 2020 BP.
  - CCR Closure program increase of plan over plan due to timing and cost increases.

## Sensitivities:

- CCR Beneficial Reuse projects (Ghent and Mill Creek Barge and/or Rail Loading) are not included and are dependent upon CCR Beneficial Reuse contracts.

# Key Capital Assumptions - Generation

## Key Assumptions:

- Mill Creek 2 offline from April through October starting in 2020 and will likely continue through 2024 to facilitate Louisville Metro Air Pollution Control District targets.
- Unit Retirements: Mill Creek 1 retirement expected 12/31/2024. The retirements of Mill Creek 2 and Brown 3 are expected in 2029.
- The next turbine overhauls by unit are as follows:
  - 2021: Ghent 1
  - 2022: Mill Creek 4
  - 2023: Trimble County 2 (Generator)
  - 2024: Cane Run 7 (CT1, CT2, and ST HP-IP)
  - 2025: Trimble County 1
- Combustion turbine (CT) outages in the plan:
  - The second set of Trimble County CT hot gas path inspections are in progress with the remaining units scheduled as follows: Unit 8 – 2021, Unit 10 – 2024
  - The third hot gas path inspection will commence on TC Unit 5 in the fall of 2020 and will include a rotor inspection.
  - A hot gas path inspection on Paddy's Run 13 is scheduled to commence in 2025.
  - E.W. Brown C inspections by unit are as follows: Unit 7- 2021, Unit 8 – 2022, Unit 9 – 2025
- The CT component outages for Cane Run 7 include a Combustion Inspection in 2022, and a major in 2024 (HGPI and turbine overhaul).
- Cane Run 7's CT's are covered by a Long-Term Program Contract (LTPC) and E.W. Brown 6 and 7 are covered by a Long-Term Service Agreement (LTSA).

# Key Capital Assumptions – Generation

## Changes from 2020 BP:

- Generation is favorable plan over plan each year for 2021 through 2024
- Non-Mechanism:
  - — Mill Creek 1 - Reductions made throughout the plan to adjust for expected unit retirement in 2024.
    - While to a lesser extent than Mill Creek 1, reductions on Mill Creek 2 and Brown 3 projects were made over the course of the plan.
  - — Coal Major Outage - Favorability in 2024 driven by movement of Ghent 3 major to an eight-year cycle as wells as adjustment to the Trimble County Unit 1 outage scope including removing the precipitator rebuild.
  - — CT Major Outage - Trimble County CT5 Major scope changed in 2021 to utilize refurbished parts. Decrease in 2024 as a result of moving commencement of Paddy's Run 13 Hot Gas Path Inspection from 2024 to 2025.
  - — Non-Major Outage - The increase in 2021 is driven largely by the movement of the Mill Creek Unit 2 outage from the spring of 2020 to the spring of 2021. Increase in 2024 driven by Ghent controls upgrades and boiler work.
  - — Reliability - The increase in 2021 includes the purchase of spare stator bars for Ghent Units 2 or 3 and Trimble County 1, and the Trimble County Limestone System Upgrade.
  - — OT Security - Capital added to the plan consistent with company strategy.
- Mechanism: Favorability in 2021 as a result of pulling forward the Brown 3 PJFF Bag change out project into 2020 from 2021 as a result of Brown 3 outages shifting from the spring to the fall.

## Sensitivities:

- As currently drafted, the Affordable Clean Energy (ACE) Rule would have significant cost impacts; however, no costs have been included in the 2021 business plan.

# 2021 Business Plan
# Capital Proposed By Area of Spend

| | 2020 Forecast | 2021 Proposed | 2022 Proposed | 2023 Proposed | 2024 Proposed | 2025 Proposed |
|---|---|---|---|---|---|---|
| Project Engineering | $ 167 | $ 230 | $ 156 | $ 132 | $ 79 | $ 45 |
| Generation | 171 | 210 | 102 | 116 | 154 | 152 |
| Transmission | 190 | 229 | 116 | 111 | 108 | 106 |
| Electric Distribution | 283 | 267 | 225 | 222 | 218 | 214 |
| Gas Distribution | 148 | 143 | 52 | 42 | 101 | 41 |
| Customer Services | 50 | 61 | 79 | 107 | 106 | 93 |
| Information Technology | 73 | 58 | 39 | 45 | 38 | 40 |
| All Other Areas | 8 | 5 | 4 | 4 | 5 | 4 |
| TOTAL | $ 1,089 | $ 1,203 | $ 772 | $ 780 | $ 809 | $ 695 |

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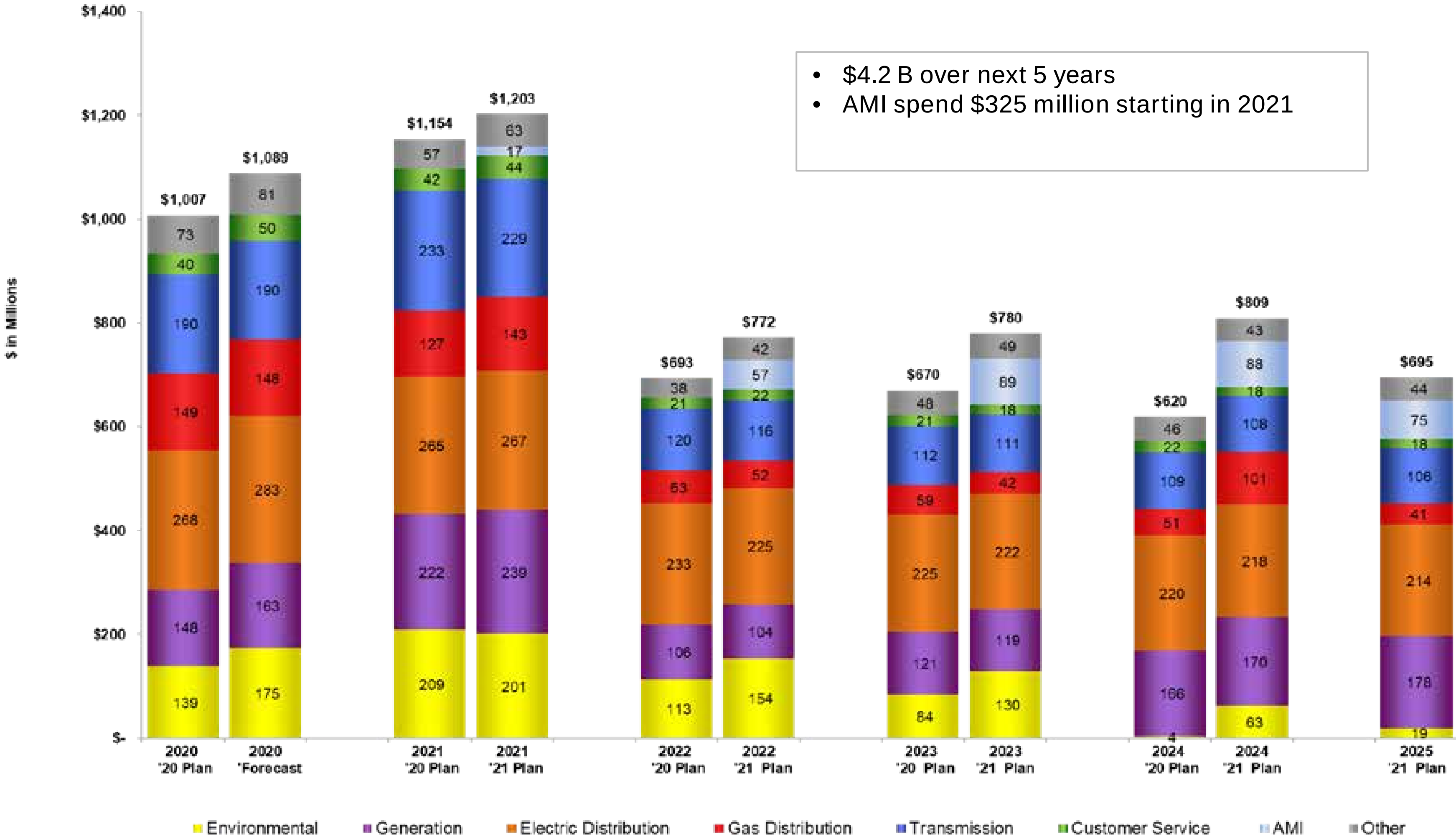
# 2021 Capital Plan versus 2020 Capital Plan




- $4.2 B over next 5 years
- AMI spend $325 million starting in 2021

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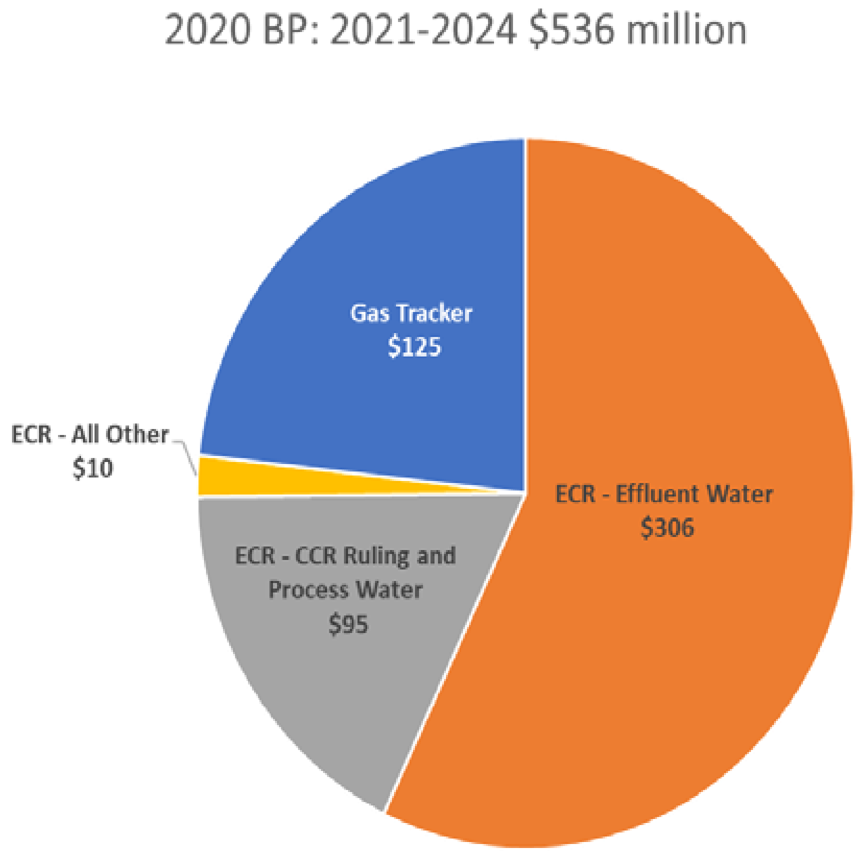
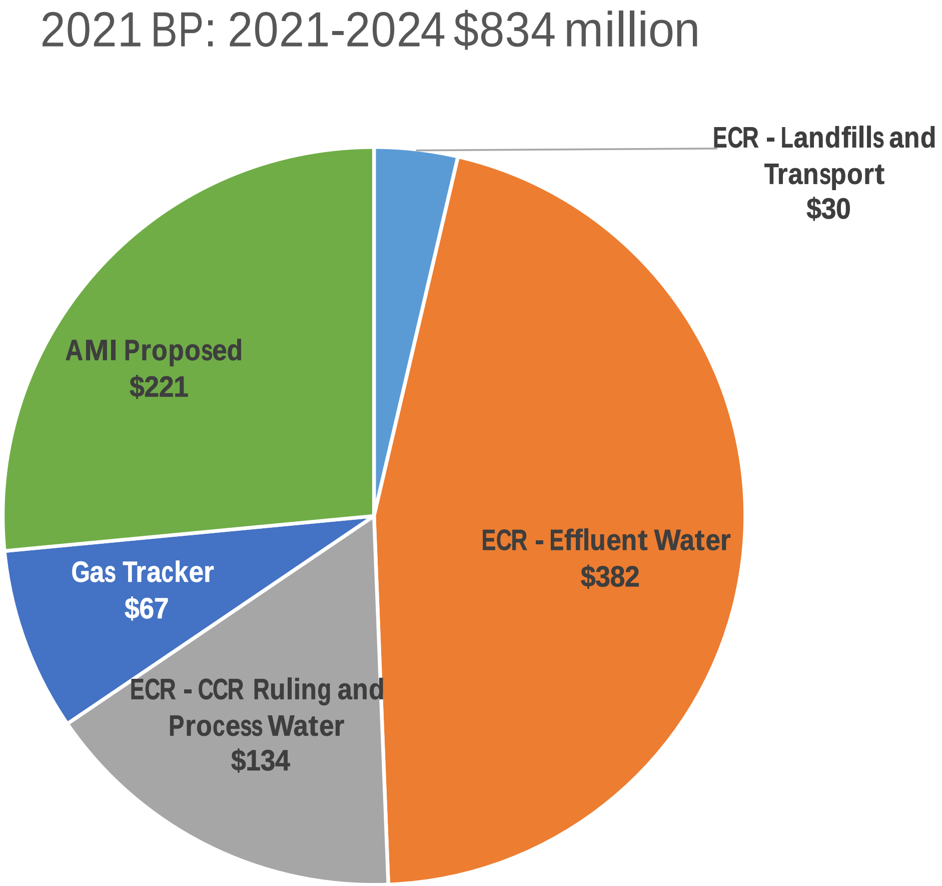
LG&E KU PPL companies

# Mechanism Investments 2021 – 2024 ($M's)




Total ECR spend is $406M in the 2020BP vs $546M in the 2021BP of which pending approval is ECR filing spend 2021BP $381.5m vs. 2020BP $306m.

Case No. 2021-00393
Attachment to Response to JI-2 Question No. 3(a)
41 of 41
Arbough/Wilson

PPL companies

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.4**

**Responding Witness: Michael P. Drake**

Q-2.4. Refer to the Companies' response to Joint Intervenors request 1.24, including the May 2018 "Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation" (referred to below as the "2018 Study")

a. The 2018 Study was reviewed February 2022. Please explain in full what that review consisted of, including identification of the person(s) responsible for the review.

b. Please provide inspection reports for the Mill Creek, Ghent, Brown, and Trimble thermal units since May 2018.

A-2.4.

a. The February 2022 review by Generation Engineering addressed the methodology and assumptions of the initial 2018 study to the extent that significant issues with boiler drums, turbines, and generators would be considerations for unit retirement.

b. All of the information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The Companies routinely inspect and maintain individual pieces of equipment associated with each generating unit and maintain documentation associated with such equipment. To the extent that the boiler drum and turbine/generator are identified as the components for which a catastrophic failure would be consideration for retirement, the Companies are providing inspection reports and summaries for this equipment since May 2018.

For the turbines and generators, reports are provided for each unit which completed a major inspection and overhaul since May 2018. The reports are generated by the contractor conducing the work and contain information regarding the condition of the equipment and repair work conducted. The inspection work is thorough, but information presented is limited to work that was performed during the outage.

For the boilers, an internal Company summary document is presented for each generating unit. These documents provide a concise condition summary of the Companies' boilers. They do not contain detailed inspection data, but rather provide information regarding the past inspection and repair work as well as future plans to maintain the outstanding record of safe and reliable operation the Companies have established.

The entire attachment is Confidential and provided separately under seal.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.5**

**Responding Witness: Daniel K. Arbough**

Q-2.5. Refer to the Companies' Response to Metro Request 1-8. Please produce the referenced "LG&E and KU Energy LLC Capital and Investment Review Policy" and the "Capital Evaluation Model."

A-2.5. Attachment 1 is the Capital and Investment Review Policy, and Attachment 2 is the Capital Evaluation Model provided in Excel format.

# LG&E AND KU ENERGY LLC Policy



## Capital and Investment Review

### Policy

The primary purpose of the Capital and Investment Review Policy is to establish a uniform process for:

1. capital planning and budgeting;
2. authorizing the expenditure of funds;
3. controlling and reporting of capital expenditures; and
4. developing review criteria for the authorization process.

Further, these policies will provide management with the necessary tools to make informed business decisions. A capital expenditure includes adding, replacing or retiring units of property through the construction or acquisition process. Generally, it is inappropriate to capitalize expenditures that are part of routine or necessary maintenance programs. If a substantial improvement is made to an asset, the following two sets of criteria should be used to determine whether or not capitalization is appropriate:

*The improvement must meet both of the following criteria:*

1. Be a minimum of $5,000.
2. Meet the definition of a capitalizable cost under the FERC Uniform System of Accounts.

*In addition, the improvement must do at least one of the following criteria:*

1. Extend the original useful life of the asset.
2. Increase the throughput or capacity of the asset.
3. Increase operating efficiency.

Questions relating to the categorization of an expenditure as capital or O&M expense should be directed to Property Accounting. The Controller will have the ultimate authority of interpreting expense versus capital decisions based on generally accepted accounting principles. See Property Accounting’s Home Page.

### Scope

This policy applies to LG&E and KU Energy LLC (“LKE” or “the Company”) and its subsidiaries.

### General Requirements

1. All capital spending that is expected to occur during the current year must be budgeted in the approved Business Plan (BP).
2. There will be no carry-over of spending capital authority from one year to the next.
3. An Authorization for Investment Proposal (AIP) must be completed in PowerPlan for all capital spending projects.

4. Projects with a total cost of $5,000 or less will be expensed.
5. An Investment Proposal (IP) and Capital Evaluation Model (CEM) must be completed for all capital spending projects greater than $1,000,000 unless otherwise approved by Director of Financial Planning & Budgeting (FP&B).
6. The Information Technology Department must approve all capital projects involving anything related to information technology.

## Capital Planning

The BP is used to inform senior management of future capital-spending projections. These plans are prepared annually on a line of business (LOB) basis and include the forecast of capital projections during the most current annual planning period. The first year of the BP, once approved, becomes the formal budget for that year.

*Carry-Over Spending:* During preparation of the BP, each LOB will review all current-year projects to determine if they will be completed as of the end of the year. If a project is expected to be in process at year-end, but not complete, it must be included in the following year's BP for additional funds to be approved.

## Construction Overheads

Per the Uniform System of Accounts, Electric Plant Instruction 4, costs related to construction activities but not directly related to a project, can still be capitalized in the form of a construction overhead or burden. This can be in the form of Local Engineering or the allocation of Administrative and General costs. See Appendix A for a detailed explanation of construction overheads and costs that can be included.

## Capital Approval Process

*Authorization for Investment Proposal:* Although specific capital projects are identified in the budgeting process, they are still subject to the Authority Limit Matrix approval requirements and all other reviews as stated on the AIP in PowerPlan. Projects are not considered approved until appropriate approvals are obtained.

The AIP is used to request the appropriate approvals for spending on capital projects. A completed AIP is subject to the following conditions:

- An AIP must be submitted and approved in PowerPlan prior to committing to or incurring any capital expenditure.
- Approvals must be obtained up to the levels designated in the Authority Limit Matrix for the dollar amount of any project (which may include multiple projects). The combined dollar amount on multiple projects grouped together using the Budget Item field in PowerPlan is the determinant for approval levels.
- Any AIP over $1,000,000 must include an IP and CEM when submitted for approval.
- A completed AIP must be submitted and approved prior to the disposal of any capital asset. In addition, an IP must be submitted for disposal projects over $1,000,000.
- A revised AIP must be submitted for significant project overruns (see below).

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

*Investment Proposal:* The IP is used to explain in detail the nature and justification of the capital project. Capital projects over $1,000,000 on a burdened basis require the submittal of an IP and CEM along with the AIP. The following information will provide senior management with consistent documentation for evaluating capital projects. The IP template is published on the Financial Planning & Analysis intranet or SharePoint Team website.

*Unbudgeted Projects:* Any capital expenditure that is not included in the original, approved budget must either be offset by a like reduction in one or more budgeted projects, approved by the Resource Allocation Committee (RAC) if subject to the RAC Charter or have prior written approval by the LKE Chief Financial Officer (CFO) and Chief Executive Officer (CEO). FP&B and/or Manager of Shared Services & Corporate Budget (SS&C) must approve AIPs for unbudgeted projects (see *FP&B and SS&C Approvals* below). Certain Generation Miscellaneous Projects, as described below, are exempt from being considered unbudgeted.

*Under-Funded Projects:* Projects that are submitted for approval that were included in the original approved budget, where the requested capital amount is greater than the budgeted amount for that project, must either be offset by a like reduction in one or more budgeted projects, approved by the RAC if subject to the its Charter or the additional funding requires prior written approval by the LKE CFO and CEO. These projects are considered "partially budgeted" in PowerPlan since the full funding is not coming from the original budget for that project. FP&B and/or SS&C must approve AIPs for under-funded projects (see *FP&B and SS&C Approvals* below).

*Retirement Only Projects*: Any Capital project for retirement purposes only that is submitted for approval, including the retirement of assets that result in a net credit, should use a retirement work order type in the PowerPlan system. The approval levels will automatically be applied based on the size of the absolute value amount for the AIP. The approvals will be required at the Director level up to $1,000,000 and at the CFO level at $1,000,000 or more.

*Transfer of Assets Between Utilities*: Any Capital project proposal that results in a transfer of assets from LG&E to KU or from KU to LG&E should include a notification email to be sent for review by the Manager of Corporate Accounting, the Manager of Corporate Finance and the Manager of Property Accounting prior to being submitted for approval in the PowerPlan system.

The project set up, which includes the work order type, must be coordinated with Property Accounting before the project is sent for approval. If the transfer between utilities is for assets with an original net book value of $1 million or more, the proponent must also notify the State Regulation and Rates department for review before the project is sent for approval.

*LG&E and KU Board and PPL approvals:* Any budget item over $50 million requires the approval of the LG&E and KU Energy Board. Budget items over $100 million additionally require the approval of the PPL Finance Committee. Cost overruns greater than 20% on budget items approved by the PPL Finance Committee must be re-approved by the Committee before spending occurs. If an overrun on a budget item results in a total cost of $100 million or more, the proposal must be approved by the PPL Finance Committee before overrun spending occurs.

*Project Overruns:* When it is apparent that the amount approved on the original AIP will be insufficient (project is expected to be 10% or $100,000 over, whichever is less, subject to a minimum of $25,000) to complete the project, **a revised AIP must be completed and submitted in PowerPlan. The revised forecasted project cost must also be included in the capital forecast to be reviewed and approved by the RAC and IC. Additionally, when completing the revised AIP, the following conditions apply (see Capital Approval Appendix on page 10):**

- If the project is $1,000,000 or below, no IP or CEM are required. Provide a clear explanation of the overrun in the revised AIP description upon submittal in PowerPlan.
- If the project overrun causes the total amount to exceed the next approval level, but did not exceed the 10% or $100,000 (subject to a minimum of $25,000) amount over the previously approved project level that requires a revised AIP, no action is required. The only exception is the IC threshold as noted below.
- If the total revised project requested is greater than $1,000,000 but less than $2 million, a revised IP and CEM are required with the submission of the revised AIP. If the original approved project was less than or equal to $1,000,000 before the overrun which brings the revised project request above this threshold, an IP and CEM are now required.
- If the project overrun is expected to be $500,000 or greater and the project had been approved by the IC, the revised project, including a revised IP and CEM, must be approved subject to the RAC Charter and presented and re-approved by the IC.
- If project overrun is $100,000 or more, but less than $500,000 and the project had been approved by the IC, provide a clear explanation of the drivers of the overrun in the revised AIP description upon submittal in PowerPlan. A revised IP and CEM are not required.
- If the previous project proposal was below the IC threshold and the revised amount is over the IC threshold, the revised proposal needs to be approved by the IC regardless of the increased amount. A revised IP and CEM are required.
- Project overrun must be offset by a like reduction in one or more budgeted projects, approved by the RAC if subject to the RAC Charter or the overspending requires prior written approval by the LKE CFO and CEO.
- Revised AIPs must be approved for the total revised dollar amount using the approval limits in the Authority Limit Matrix.

*FP&B and SS&C Approvals*: Unbudgeted projects or those projects requiring an IP and CEM (i.e., over $1,000,000) must include FP&B and SS&C review and approval. Unbudgeted projects less than $250,000 require SS&C Manager approval and those $250,000 and over require FP&B Director approval. The FP&B Director has PowerPlan system AIP approval delegation authority for the Investment Committee (whose approval is noted in Investment Committee meeting minutes or email vote) as well as for the President and CEO (whose approval is noted via signature on the IP document) and will approve AIPs in the system only after confirmation of the fully approved IP document being attached to the AIP.

Budgeted projects less than or equal to $1,000,000 are approved as normally required by the Authority Limit Matrix and do not require the approval of FP&B and SS&C.

*Blankets & Miscellaneous Projects:* Homogeneous projects less than $500,000, not able to be identified during the budgeting process, can be funded by either a blanket project or a miscellaneous project as outlined. Blanket projects are used to procure routine work, which lacks detail when preparing the budget. Blanket projects are approved annually in the 4th quarter by the Investment Committee or during the Officer review of the Capital Budget. New blanket capital projects require the approval of both Property Accounting and FP&B. To open new blanket projects, a partial AIP in the amount of $10,000 must go through the approval process in PowerPlan. A miscellaneous project is used by each generating plant and LOB for small individual projects which arise during the year and which cannot be specifically anticipated during the budgeting process. Miscellaneous projects do not require an AIP but will be either used as the funded transfer on another project's AIP or opened and as money is spent then information detail will be provided to the Property Accounting department.

*Reimbursable Projects:* Projects which will have all or a portion of the spending amount reimbursed by an outside party must follow the same guidelines as non-reimbursable projects, except as noted below:

- Tax Department review indicating whether Contribution in Aid of Construction is taxable must occur prior to any reimbursement agreement greater than $25,000 being finalized and evidence of such review must be attached to the AIP. This does not apply to customer refund agreements.
- If a fully executed agreement specifying the terms of reimbursement is attached to an AIP with gross spending under $2 million, the net spending amount may be used to determine whether an IP and CEM are required.
- Third Party jointly-owned utility projects under the specified gross spending thresholds qualify for this exception without requiring the attachment of the executed joint ownership agreement.
- For all projects, the gross spending amount must always be used to determine the appropriate approval level.

*Government-Mandated/Regulatory Compliance Projects:* Projects which are not reimbursable but which are mandated by governmental legislation or other governmental authority must follow the same guidelines as all other projects except that for such AIPs with gross spending under $2 million neither the IP nor the CEM are required, provided that the appropriate legislative docket numbers or applicable statute references are provided with the AIP.

*Preliminary Survey and Investigation:* Projects that are originally set up for preliminary survey and investigation are treated as indirect projects and are auto approved and opened in PowerPlan. All amounts recorded as preliminary survey and investigation must be capital in nature. Once the preliminary survey and investigation work is complete, the determination must be made if the project will move forward as capital or be abandoned and expensed. If the project moves forward as capital, a new project must be created in PowerPlan and must follow the approval levels based on the Authority Limit Matrix. It is the responsibility of the budget coordinator to notify Property Accounting and make the appropriate accounting transactions to move preliminary survey and investigation charges to capital or to expense as appropriate.

**Early Activation Guidelines**
In order for a project to be early activated, the following criteria must be met:

1. The expenditure must be the result of a true emergency which is defined as one of the following: 1) the expenditure is needed to address an immediate safety risk; 2) the equipment has failed; or 3) a material problem has been found, requiring it to be replaced immediately in order to maintain the reliability of the system.

OR

2. The equipment vendor has provided a quote for the capital purchase that is only valid for a short period of time. The time frame would not be long enough to complete all the necessary paperwork and acquire all necessary approvals in time to place the order at the reduced price.

Process requirements for an early activated AIP are as follows:

- For each AIP that is early activated, Property Accounting must first receive email approval from the highest level of LOB authority based on the total amount of the AIP as per the AIP approval process. FP&B and SS&C must also be copied on this email. Should the AIP be for an unbudgeted project, approval from FP&B and SS&C will be required for the early activation.

- In the event the project has been previously approved by the IC, the above email from the highest LOB authority would not be required. Instead, verification from FP&B that the project had indeed been approved by the IC would be sufficient approval.

- The approval request email must include the following information:
    - Project number
    - Project description
    - Total project amount
    - Name of the individual whose highest level of authority is required, and any associated delegation of authority (DOA)
    - Description of the need for the early activation
    - For an unbudgeted project, the budgeted project number that will cover the unbudgeted spending.

- Additionally, for either scenario 1 or 2 above, an automated AIP must be submitted for $10,000 and approved by the project manager and budget coordinator for the project in order for the project to be moved to “open” status in PowerPlan.

- Property Accounting will maintain a log of early activated projects, and copies of the email approvals will be filed with the AIP.

## LG&E AND KU ENERGY LLC Policy

**Capital and Investment Review**

- A revised AIP (for the full project amount) for all projects that are early activated must be received by Property Accounting, or FP&B if necessary, with all required approvals, as soon as possible, but no later than 30 business days after the early activation. Repeated failure to comply with this timing may require email approval by the appropriate LOB VP for early activation of all future AIPs.

**Project In-Service and/or Completion**
Upon project in-service and/or completion, the project manager or budget coordinator most familiar with the project is required to do the following:

1. Verify completion date (if the date is not correct, it needs to be updated in PowerPlan). Entering a completion date changes the project status to "completed".
2. Verify actual in-service date (if the date is not correct, it needs to be updated in PowerPlan). Entering an in-service date without a completion date changes the project status to "in-service". Verify actual installed costs and actual removal costs (report/explain any variances greater than 10% from the AIP to Property Accounting).
3. Verify units of property installed and units of property retired (report to Property Accounting if different from AIP).

**Leases**
Prior to the execution of any new lease entered into on behalf of the Company, a review must be conducted by the budget coordinator for the appropriate LOB, Regulatory Accounting and Reporting and the Tax department to determine if the lease is structured as a finance or operating lease. Additional reviews by Legal and Corporate Finance may be required depending on the total amount of the lease. See the LKE Lease Policy for more details.

**Penalties for Noncompliance:** Failure to comply with this policy may result in disciplinary action, up to and including discharge.

**Reference:** Authority Limit Matrix; CEM; Lease Policy; Resource Allocation Committee Charter; FERC Uniform System of Accounts; and Investment Proposal forms.

**Key Contact:**

- Financial Planning & Budgeting
- Shared Services & Corporate Budgeting
- Accounting Matters: Property Accounting and Controller
- Capital Leases: Corporate Finance and Regulatory Accounting and Reporting

**Administrative Responsibility:** Chief Financial Officer.
Revision Dates: 12/01/07, 04/04/08, 12/31/08, 7/20/2009, 5/1/2014, 12/1/2014, 5/16/2016, 1/27/2017, 4/24/2017, 6/1/2017, 2/12/2018, 1/01/2019,5/1/2019, 2/1/2020, 2/1/2021

(See Capital Approval Appendix B for additional reference)

## APPENDIX A: CONSTRUCTION OVERHEADS –CAPITALIZATION POLICY AND CHARGING ACTIVITY GUIDANCE

### Local Engineering

Local engineering is used mainly by personnel in operations, including budget oversight, that are involved in capital activities related to their lines of business. Costs are accumulated in a clearing account (1846xx) and allocated to capital via the burdening process. Each line of business and the applicable budgeting functions charge costs based on the following guidelines:

### Budgeting Activities

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in the A&G study):

- Capital project work (e.g. setting up, in-service, closing, etc.)
- Analysis for capital projects (Investment proposals, etc.)
- Annual Business Planning activity for capital including strategy development
- Monthly forecasting activities for capital
- Preparation of Authorized Investment Proposals (AIPs) and associated support
- Capital budget and forecast review meetings
- Investment Committee and RAC meetings preparation and support

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Non-capital project work (e.g. setting up, closing, etc.)
- Answering general questions (e.g. capital vs. O&M, budget, transfers, etc.)
- General meetings (if meeting relates to a capital project, depending on the topic, it may be appropriate to capitalize to that capital project)
- Formulating policies
- Preparing reports (e.g. FERC reports)
- Audit work
- General accounting work
- Creating and reviewing financial reports
- Training

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

### Generation Activities

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in the A&G study):

- As-built drawings
- RFP process for capital project
- Providing work direction and oversight on capital projects
- Development of new material or construction standards
- Contract activity for capital projects
- Inspecting multiple capital jobs
- Job closing
- New mapping of installed assets
- Design work on capital projects
- Detailed design/technical review of capital projects
- Scheduling crews working on capital projects
- Investment Committee and RAC meetings preparation and support
- Site visits
- Locating for capital activities*

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Editing or updating existing construction standards
- Relocating of facilities without replacements of retirement units
- Oversight of maintenance activities
- Oversight of general operations (e.g. meetings)
- Failed material analysis
- Analysis to determine condition (e.g. repair or replace)
- Locating for maintenance activities*

* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering.

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

### Electric Transmission Activities

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (if not included in the A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets
- Inspecting multiple capital jobs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC meetings preparation and support
- Scheduling crews working on capital projects
- Site visits
- Providing work direction on capital projects
- Locating for capital activities*

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Oversight of maintenance activities
- Relocating of facilities without replacements of retirement units
- Editing or updating existing construction standards
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Coordination of maintenance activities (e.g. development of maintenance standards, coordination of crews to perform maintenance activities, answering maintenance questions)
- Oversight of general operations (e.g. meetings)
- Approving change orders
- Failed material analysis
- Locating for maintenance activities*
- Line patrol

* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering.

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

### Electric Distribution Activities

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets

Inspecting multiple capital jobs

- CPC designs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC preparation and support
- Scheduling crews working on capital projects
- Site visits
- Providing work direction on capital projects
- Locating for capital activities*

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Oversight of maintenance activities
- General inspections
- Updating device settings or equipment adjustment
- Evaluating repair/replace scenarios
- Editing or updating existing construction standards
- Feeder phase rebalancing
- Relocating of facilities without replacements of retirement units
- Line patrol
- Coordination of maintenance activities (e.g. development of maintenance standards, coordination of crews to perform maintenance activities, answering maintenance questions)
- Oversight of general operations (e.g. meetings)
- Approving change orders
- Failed material analysis
- High level review of scoping memos and design concepts
- Analysis to determine condition (e.g. repair or replace)
- Locating for maintenance activities*

* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

### Gas Activities

Individuals must meet all three of the following criteria to charge the local engineering overhead account:

1. Have a direct relationship with construction work related to the functional overhead they are charging time to.
2. Be working on so many capital projects it is not feasible to charge their time directly to those projects.
3. Be performing a capital activity such as the examples given below.

Capital Activities (not included in A&G study):

- As-built drawings
- Switching orders for capital work
- RFP process for capital project
- Development of new material or construction standards
- Job closing
- New mapping of installed assets
- Inspecting multiple capital jobs
- CPC designs
- Design work on capital projects
- Detailed design/technical review of capital projects
- Investment Committee and RAC preparation and support
- Scheduling crews working on capital projects
- Site visits
- Locating for capital activities*
- Site visits

Note: Unplanned work should be charged to the appropriate specific or blanket project.

The examples given below should be charged to an appropriate expense project.

O&M Activities:

- Management administration (i.e. approving time, approving invoices, performance reviews, etc.)
- Line Patrol
- Failed material analysis
- Approving change orders
- Evaluating repair/replace scenarios
- Surveys (e.g. leak or atmospheric)
- Pressure monitoring and recording
- General inspections
- Updating device settings or equipment adjustment
- Analysis to determine condition (e.g. repair or replace)
- Editing or updating existing construction standards
- Relocating of facilities without replacements of retirement units
- Oversight of maintenance activities
- Oversight of general operations (e.g. meetings)
- High level review of scoping memos and design concepts
- Leak repair not involving retirement units
- Locating for maintenance activities*

* Locating activities resulting in replacements of assets can be capitalized and charged to local engineering

**LG&E AND KU ENERGY LLC Policy**

## Capital and Investment Review

### Administrative and General study (every two years)

Per the Uniform System of Accounts and NARUC Interpretation No. 59, periodic studies must be performed to determine the percentage of administrative and general costs capitalized to construction. Capitalized costs are required to have a provable relationship to construction activities. The purpose of this survey is to determine the percentage of FERC accounts 920 (Administrative and General Salaries) and 921 (Administrative Office Supplies and Expenses) that should be allocated to construction and other non-operating expenses.
Every other year, a survey is sent to the Line of Business Budget analysts supporting those departments charging time to FERC Account 920 and will be used as the basis to allocate a portion of costs to construction activities. The survey requests information by company and applicable expenditure organizations with data provided as a percentage of labor. The survey includes only expenditure organizations that had a combined total labor for LG&E and KU of $100,000 or more charged to FERC account 920 for the most recent 12-month calendar year prior to the survey year.

The type of work included in the analysis to compute an accurate percentage for time spent supporting capital projects should align with the guidance for local engineering. In addition, accounting and financing activities associated with capital activity should also be considered including the processing of AIPs, unitization of projects, risk management and debt issuances.
Each month, Regulatory Accounting and Reporting will prepare an entry to credit FERC account 922 and debit the Administrative and General clearing account. This amount in the clearing account will be allocated to capital projects via the burdening process. Rates will be calculated and monitored in accordance with the Oracle Burdening Process Accounting policy.

# LG&E AND KU ENERGY LLC Policy

## Capital and Investment Review

### APPENDIX B

**General Approval Requirements**

| Investment | Action Required |
|---|---|
| > $5k | • AIP required<br>• various approvals – see ALM |
| > $1m | • Investment Proposal required<br>• CEM required<br>• AIP required<br>• Senior Officer approval and others noted in ALM |
| > $2m (for Real Property > $500k) | • Investment Committee approval and above mentioned items<br>• LKE CEO approval needed |
| > $50m | • Investment Committee approval and above mentioned items<br>• LGE and KU Energy Board approval needed |
| > $100m | • Investment Committee approval and above mentioned items<br>• LGE and KU Energy Board approval needed<br>• PPL Finance Committee approval needed |

Note: IT approval is needed for any IT project

**Project Overruns**

If a project is expected to be 10% or $100k over, whichever is less, subject to a minimum of $25k, a revised AIP must be completed before the overrun occurs and the following conditions apply for the revised approval request:

| Initial Investment Amount | Increase | Action Required |
|---|---|---|
| < $1m | Will bring project over $1m for the first time | • Investment Proposal required<br>• CEM required<br>• Revised AIP |
| | Will bring project over IC threshold | • Investment Proposal required<br>• CEM required<br>• Revised AIP<br>• IC Approval required |
| > $1m and Under IC Threshold | > $100k or 10%, whichever is less, subject to a minimum of $25k | • Revised IP required<br>• Revised CEM required<br>• Revised AIP |
| | Will bring project over IC threshold | • Revised IP required<br>• Revised CEM required<br>• Revised AIP<br>• IC Approval required |

The attachment is being provided in a separate file in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.6**

**Responding Witness: Stuart A. Wilson**

Q-2.6. Refer to the Companies' response to Commission Staff's Question 26(b)(3), which states *inter alia*: "The Companies would consider NGCC without CCS a plausible technology option under certain circumstances." Please fully explain the circumstances under which the Companies would consider NGCC without CCS including, but not limited the following: expectations related to carbon regulation; expected useful life of the resource; capital costs; variable and fixed operating and maintenance costs; technology advancements; and any other factors the Companies consider relevant.

A-2.6. The Companies would evaluate NGCC without CCS over a broad range of scenarios and would consider it a viable resource if it was least-cost in a majority of those scenarios. See the response to PSC 2-3.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.7**

**Responding Witness: John Bevington / Stuart A. Wilson**

Q-2.7. Please refer to the Companies' response to Commission Staff's Q4, pg 14 PDF of 02-PSC_DR1_LGE_KU_Responses_2021-00393.pdf.

a. The companies quote from Case No. 2018-00348, Order Appx. (Ky. PSC July 20, 2020) the statement that the "Companies should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders." Please describe the work of this DSM advisory group since the last IRP, and what recommendations and inputs from stakeholders have been included in this IRP or what recommendations and inputs the companies are currently following or planning to follow in the next 15 years.

b. The companies quote from the same order: "Staff encourages LG&E/KU to continue exploring cost- effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time." The companies mention in LGE_KU_2021_IRP_Volume_III.pdf, pg 76 pdf that: "Successful deployment of DSM programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes." Aside from the modular nature of battery storage, what other factors would be weighed in deciding whether to eliminate battery storage vs eliminate SCCT development?

A-2.7.

a. The Companies are proud of the collaboration and ongoing efforts of all stakeholders in the DSM Advisory Group. Since the last IRP, the Companies have held four meetings.[4] The agendas, meeting materials, attendee lists, and minutes are all posted online and provide complete descriptions of the past work of the group.[5]

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[4] The meetings occurred on 11/8/2019, 11/9/2020, 9/17/2021, and 12/3/2021.
[5] https://lge-ku.com/dsm.

One example of a recommendation from a meeting that became part of the Companies' DSM offerings beginning in January 2019 relates to increasing eligibility in the WeCare program. A group participant asked if the income requirement could be expanded so that more customers could be eligible for the program. As a result, the Companies adjusted the minimum income requirement from LIHEAP's at 150% of poverty level to DOE's Weatherization Assistance Plan (WAP) at 200%, which also allowed for simplified eligibility determination between the two programs (WeCare and WAP). Another example relates to determining rules for DSM Industrial opt-out and opt-in. See Case No. 2017-00441, Exhibit GSL-1, Section 1.2, starting at page 12 of 182 for a detailed description of the entire process.[6]

b. The Companies' objective is to provide safe and reliable service to customers at the lowest reasonable cost. The Companies will evaluate the operational characteristics and attributes of generation technologies and DSM programs in determining which portfolio of resources meets this objective.

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[6] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.8**

**Responding Witness: Stuart A. Wilson**

Q-2.8. Refer to the Companies' Response to Joint Intervenors' request 1.2. Please provide a detailed explanation as to the claims that the IRP reflects the Companies' objective "to provide all customers, irrespective of income or other demographic criteria, with safe and reliable service at the lowest reasonable cost," when the Companies have not considered or performed any analysis on the impacts of the proposed Integrated Resource Plan (IRP) on residential customers with low- and fixed-incomes.

A-2.8. The Companies believe that providing safe and reliable service at the lowest reasonable cost is the best approach for serving all customers, irrespective of their income status. Also, nearly two decades ago the Commission stated that special low-income rates are not permissible.[7] To the Companies' knowledge, the Commission has never deviated from that position. Indeed, the Commission stated just three years ago that it could not consider affordability in determining the reasonableness of rates.[8] This approach is consistent with the requirement of KRS 278.170(1) not to discriminate with regard to rates or service for "doing a like and contemporaneous service under the same or substantially the same conditions." Consistent with its own precedent and Kentucky statute, the Commission's IRP regulation does not address customers' income status;[9] rather, the Necessity, Function, and Conformity section of the Commission's IRP regulation states that it "prescribes rules for regular reporting and commission

[7] *Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 82-84 (Ky. PSC Feb. 28, 2005).

[8] *Electronic Application of Kentucky-American Water Company for an Adjustment of Rates*, Case No. 2018-00358, Order at 3 (Ky. PSC Jan. 3, 2019), *citing Gainesville Util. Dept. v. Fla. Power Corp.*, 402 U.S. 515, 528 (1971) ("We caution movants that affordability is not a factor that the Commission can consider because KRS 278.170(1) prohibits rates that establish an unreasonable preference between classes of service for doing a like service under the same or substantially the same conditions. Further, the United States Supreme Court has held that a focus on the ability of the customer to pay for utility service is the concern of the utility and not the regulatory agency because the regulatory agency is charged with both assuring the public of reliable, efficient service at a reasonable price and assuring the utility that it may collect fair, just, and reasonable rates.").

[9] *See* 807 KAR 5:058.

review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for ***all*** customers within their service areas …."[10] Therefore, the Companies believe there is neither a requirement nor authority to differentiate between low- and fixed-income customers and all other customers in an IRP.

[10] *Id.* (emphasis added).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.9**

**Responding Witness: Stuart A. Wilson**

Q-2.9. The Companies state in A-1.2 (a) of Response to Joint Intervenors' Initial Request for Information (Case No. 2021-00393) that "the Companies do not have access to customer-specific income data." While the Companies claim is that they do not have access to this customer-specific data, that does not mean the Companies cannot layer income data from other sources (e.g. U.S. Census American Community Survey data, MHC's State of Metropolitan Housing Reports, Louisville Metro Center for Health Equity's Health Equity Report, 2020 Analysis of Impediments to Fair Housing Choice in Louisville Metro, Ky, etc.) to gain a better understanding of the Companies customer residential service location data when layered with other publicly available data on geographic income and poverty distribution by census tract to better understand the impact of the proposed IRP on low- and fixed-income residential customers. Please provide a detailed explanation as to the reasoning the Companies did not access and layer additional publicly available data on top of their customer-specific location data to analyze the IRP's impact on fixed- and low-income residential customers.

A-2.9. See the response to Question No. 2.8.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.10**

**Responding Witness: Stuart A. Wilson**

Q-2.10. Please provide a detailed explanation as to the reasoning for the Companies not analyze historical data on low-income households in the preparation of the proposed IRP.

A-2.10. See the response to Question No. 2.8.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.11**

**Responding Witness: Stuart A. Wilson**

Q-2.11. Please provide a detailed explanation as to why no analysis was performed on the impact of "expected increases in the cost of generation" on low-income households.

A-2.11. See the response to Question No. 2.8.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILTIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.12**

**Responding Witness: John Bevington / Stuart A. Wilson**

Q-2.12. Please provide a detailed explanation as to why no analysis was considered during the development of the proposed IRP pertaining to the planning and development of new DSM programs targeted at low-income households.

A-2.12. See the response to PSC 1-4.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.13**

**Responding Witness: Stuart A. Wilson**

Q-2.13. Please provide a detailed explanation as to why studies related to environmental and health impacts on low-income communities and communities of color were not considered as a part of the process in developing the proposed IRP.

A-2.13. See the response to Question No. 2.8. The same reasoning applies equally concerning the request's inquiry regarding communities of color. The Companies provide service on a non-discriminatory basis, as they both desire to do and as KRS 278.170 requires them to do. The Companies are grateful to serve diverse communities with a diverse workforce, and to do so on a non-discriminatory basis.

Also, the Commission has explicitly stated, "The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service,"[11] and the Commission's IRP regulation does not require utilities to analyze such factors. Therefore, the Companies do not address such factors in their IRPs.

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[11] Case No. 2017-00441, Order at 28 (Ky. PSC Oct. 5, 2018).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.14**

**Responding Witness: Stuart A. Wilson**

Q-2.14. Please provide a detailed explanation as to why no studies related to the impact of economic disparities on low-income communities and communities of color were considered as a part of the process to develop the proposed IRP

A-2.14. See the response to Question No. 2.13.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.15**

**Responding Witness: Stuart A. Wilson**

Q-2.15. 14.2 percent of Louisville/Jefferson County residents live below the federal poverty line, higher than the U.S. rate of 13.4 percent. Low- and fixed-income residential customers make up a significant percentage of your customer base and any analysis and/or studies conducted during the IRP development process must include targeted analysis of low- and fixed-income residents. Why have low- and fixed-income residential customers been ignored during the analysis process in developing the proposed IRP by the Companies?

A-2.15. The Companies categorically deny that they have "ignored" any of their customers. See the response to Question No. 2.8.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.16**

**Responding Witness: David S. Sinclair**

Q-2.16. Refer to the Companies' response to Commission Staff's Request 58, in which the Companies stated: "The reporter's question was about the forecast of CO2 emissions that was provided in response to data request MA-KFTC-MHC-3 Question No. 6(4) in Case Nos. 2020-00349 and 00350. As shown in response to Question No. 6(1) of that same data request, all retiring coal units from 2028 on were assumed to be replaced with a 1x1 NGCC. Thus, the assumptions associated with that particular forecast did not even consider future renewable resources or any other technologies. The 2021 IRP considered a broad range of technologies and demonstrates that renewable technologies are likely to be an important resource in the coming 15 years covered by the IRP."

Please clarify this response.

a. Are the Companies stating that the forecast presented in response to questions 6(1) and 6(4) in Case Nos. 2020-00349 and 00350 was inaccurate and inconsistent with the IRP forecast?

b. Please explain why, in their response to questions 6(1) and 6(4) in Case Nos 2020-00349 and 00350, the Companies assumed all retiring coal units would be replaced with 1x1 NGCC.

c. Please provide a side-by-side comparison of the Companies' forecast CO2 emissions from Case Nos. 2020-00349 and 350 and the 2021 IRP, including projected energy generation and the assumed generation portfolio mix for each year in each forecast, and the percentage contribution of each generator to energy production and CO2 emissions. Please confirm if the Companies consider the forecast from the 2021 IRP to be the more realistic scenario and if not, why not.

A-2.16.

a. No. There is no way to determine the "accuracy" of a forecast until after the forecasted event has occurred (or does not occur). The Companies' 2020 base rate cases focused on the forecasted test year of July 1, 2021 to June 30, 2022, while the IRP focuses on a wide variety of possible futures and the technologies that would be least-cost to reliably serve customers' energy needs through 2036.

b. See the response to PSC 1-58.

c. See attached. The values from these scenarios reflect results from the detailed hourly dispatch PROSYM model.[12]

The Companies apply a "reasonableness" standard to their forecasting and modeling based on the quality and capability of the people preparing the forecast, the quality of the models and assumptions used, and the relationship of the forecast results to historical experiences and other forecasts in the public domain. Applying that standard, the Companies believe the cited emissions forecast from the Companies' 2020 base rate cases and the 2021 IRP forecasts are all reasonable; each forecasts reflects the best assumptions available at that particular point in time. But the Companies consider the 2021 IRP to be the more complete analysis because it reflects a broad range of possible futures.

[12] The Companies used PROSYM to model detailed annual production costs and PLEXOS for expansion planning, which results in immaterial differences in $CO_2$ emissions.

| Year | Annual $CO_2$ Emissions (000s tons) | | Annual Generation (GWh) | |
|---|---|---|---|---|
| | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2022 | 29,052 | 28,995 | 31,803 | 32,233 |
| 2023 | 29,095 | 29,331 | 31,774 | 32,080 |
| 2024 | 29,600 | 29,395 | 31,769 | 32,045 |
| 2025 | 28,841 | 28,270 | 31,631 | 31,838 |
| 2026 | 28,727 | 28,240 | 31,538 | 31,648 |
| 2027 | 28,648 | 27,942 | 31,422 | 31,532 |
| 2028 | 29,084 | 26,557 | 31,362 | 31,518 |
| 2029 | 28,068 | 26,068 | 31,201 | 31,370 |
| 2030 | 26,213 | 25,956 | 31,053 | 31,279 |
| 2031 | 26,415 | 26,047 | 31,019 | 31,243 |
| 2032 | 26,527 | 26,301 | 31,025 | 31,284 |
| 2033 | 26,383 | 26,040 | 30,975 | 31,196 |
| 2034 | 23,437 | 21,248 | 30,970 | 31,348 |
| 2035 | 22,010 | 21,432 | 30,969 | 31,329 |
| 2036 | 22,046 | 21,450 | 31,009 | 31,492 |

| Year | Generation Type | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2022 | Coal | 24,211 | 24,174 | 75.6% | 75.0% |
| 2022 | Gas | 6,819 | 6,696 | 21.3% | 20.8% |
| 2022 | Hydro | 390 | 387 | 1.2% | 1.2% |
| 2022 | Solar | 18 | 17 | 0.1% | 0.1% |
| 2022 | Purchases | 572 | 958 | 1.8% | 3.0% |
| 2022 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2023 | Coal | 24,265 | 24,689 | 76.0% | 77.0% |
| 2023 | Gas | 6,689 | 6,211 | 21.0% | 19.4% |
| 2023 | Hydro | 389 | 388 | 1.2% | 1.2% |
| 2023 | Solar | 18 | 241 | 0.1% | 0.8% |
| 2023 | Purchases | 547 | 550 | 1.7% | 1.7% |
| 2023 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2024 | Coal | 25,003 | 24,823 | 78.2% | 77.5% |
| 2024 | Gas | 5,998 | 6,026 | 18.8% | 18.8% |
| 2024 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2024 | Solar | 18 | 240 | 0.1% | 0.7% |
| 2024 | Purchases | 550 | 567 | 1.7% | 1.8% |
| 2024 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2025 | Coal | 23,878 | 23,568 | 74.9% | 74.0% |
| 2025 | Gas | 7,019 | 6,639 | 22.0% | 20.9% |
| 2025 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2025 | Solar | 18 | 615 | 0.1% | 1.9% |
| 2025 | Purchases | 556 | 628 | 1.7% | 2.0% |
| 2025 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2026 | Coal | 23,507 | 23,608 | 73.9% | 74.6% |
| 2026 | Gas | 7,334 | 6,436 | 23.1% | 20.3% |
| 2026 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2026 | Solar | 18 | 615 | 0.1% | 1.9% |
| 2026 | Purchases | 549 | 601 | 1.7% | 1.9% |
| 2026 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2027 | Coal | 23,593 | 23,237 | 74.4% | 73.7% |
| 2027 | Gas | 7,186 | 6,686 | 22.6% | 21.2% |
| 2027 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2027 | Solar | 18 | 608 | 0.1% | 1.9% |
| 2027 | Purchases | 543 | 613 | 1.7% | 1.9% |
| 2027 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2028 | Coal | 24,150 | 21,690 | 76.1% | 68.8% |
| 2028 | Gas | 6,625 | 7,037 | 20.9% | 22.3% |
| 2028 | Hydro | 391 | 388 | 1.2% | 1.2% |
| 2028 | Solar | 18 | 1,806 | 0.1% | 5.7% |
| 2028 | Purchases | 553 | 597 | 1.7% | 1.9% |
| 2028 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2029 | Coal | 22,965 | 21,227 | 72.6% | 67.7% |
| 2029 | Gas | 7,723 | 7,354 | 24.4% | 23.4% |
| 2029 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2029 | Solar | 18 | 1,801 | 0.1% | 5.7% |
| 2029 | Purchases | 537 | 600 | 1.7% | 1.9% |
| 2029 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2030 | Coal | 20,453 | 21,007 | 64.9% | 67.2% |

| Year | Generation Type | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2030 | Gas | 10,103 | 7,479 | 32.1% | 23.9% |
| 2030 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2030 | Solar | 18 | 1,800 | 0.1% | 5.8% |
| 2030 | Purchases | 550 | 606 | 1.7% | 1.9% |
| 2030 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2031 | Coal | 20,864 | 21,342 | 66.2% | 68.3% |
| 2031 | Gas | 9,683 | 7,126 | 30.7% | 22.8% |
| 2031 | Hydro | 390 | 387 | 1.2% | 1.2% |
| 2031 | Solar | 18 | 1,795 | 0.1% | 5.7% |
| 2031 | Purchases | 550 | 593 | 1.7% | 1.9% |
| 2031 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2032 | Coal | 21,065 | 21,653 | 66.9% | 69.2% |
| 2032 | Gas | 9,446 | 6,843 | 30.0% | 21.9% |
| 2032 | Hydro | 391 | 388 | 1.2% | 1.2% |
| 2032 | Solar | 18 | 1,798 | 0.1% | 5.7% |
| 2032 | Purchases | 558 | 603 | 1.8% | 1.9% |
| 2032 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2033 | Coal | 20,783 | 21,272 | 66.1% | 68.2% |
| 2033 | Gas | 9,700 | 7,138 | 30.8% | 22.9% |
| 2033 | Hydro | 390 | 388 | 1.2% | 1.2% |
| 2033 | Solar | 18 | 1,793 | 0.1% | 5.7% |
| 2033 | Purchases | 558 | 606 | 1.8% | 1.9% |
| 2033 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2034 | Coal | 16,473 | 15,535 | 52.2% | 49.6% |
| 2034 | Gas | 14,120 | 9,214 | 44.8% | 29.4% |
| 2034 | Hydro | 390 | 369 | 1.2% | 1.2% |
| 2034 | Solar | 18 | 5,614 | 0.1% | 17.9% |
| 2034 | Purchases | 549 | 616 | 1.7% | 2.0% |
| 2034 | Batteries | 0 | 0 | 0.0% | 0.0% |
| 2035 | Coal | 14,340 | 15,801 | 45.5% | 50.4% |
| 2035 | Gas | 16,226 | 8,918 | 51.5% | 28.5% |
| 2035 | Hydro | 390 | 373 | 1.2% | 1.2% |
| 2035 | Solar | 18 | 5,615 | 0.1% | 17.9% |
| 2035 | Purchases | 558 | 615 | 1.8% | 2.0% |
| 2035 | Batteries | 0 | 7 | 0.0% | 0.0% |
| 2036 | Coal | 14,440 | 15,909 | 45.7% | 50.5% |
| 2036 | Gas | 16,236 | 8,965 | 51.3% | 28.5% |
| 2036 | Hydro | 391 | 371 | 1.2% | 1.2% |
| 2036 | Solar | 18 | 5,626 | 0.1% | 17.9% |
| 2036 | Purchases | 542 | 609 | 1.7% | 1.9% |
| 2036 | Batteries | 0 | 11 | 0.0% | 0.0% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2022 | Brown 3 | 793 | 1,038 | 2.5% | 3.2% |
| 2022 | Ghent 1 | 2,477 | 2,611 | 7.7% | 8.1% |
| 2022 | Ghent 2 | 2,677 | 2,628 | 8.4% | 8.2% |
| 2022 | Ghent 3 | 2,464 | 2,552 | 7.7% | 7.9% |
| 2022 | Ghent 4 | 2,165 | 2,213 | 6.8% | 6.9% |
| 2022 | Mill Creek 1 | 2,010 | 1,806 | 6.3% | 5.6% |
| 2022 | Mill Creek 2 | 801 | 790 | 2.5% | 2.4% |
| 2022 | Mill Creek 3 | 2,628 | 2,162 | 8.2% | 6.7% |
| 2022 | Mill Creek 4 | 2,691 | 2,572 | 8.4% | 8.0% |
| 2022 | Trimble County 1 | 2,592 | 2,413 | 8.1% | 7.5% |
| 2022 | Trimble County 2 | 2,913 | 3,390 | 9.1% | 10.5% |
| 2022 | Cane Run 7 2X1 | 5,278 | 4,907 | 16.5% | 15.2% |
| 2022 | Brown 5 | 62 | 39 | 0.2% | 0.1% |
| 2022 | Brown 6 | 100 | 58 | 0.3% | 0.2% |
| 2022 | Brown 7 | 65 | 49 | 0.2% | 0.2% |
| 2022 | Brown 8 | 6 | 9 | 0.0% | 0.0% |
| 2022 | Brown 9 | 10 | 20 | 0.0% | 0.1% |
| 2022 | Brown 10 | 10 | 18 | 0.0% | 0.1% |
| 2022 | Brown 11 | 5 | 9 | 0.0% | 0.0% |
| 2022 | Haefling | 0 | 1 | 0.0% | 0.0% |
| 2022 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2022 | Paddys Run 12 | 0 | 1 | 0.0% | 0.0% |
| 2022 | Paddys Run 13 | 62 | 105 | 0.2% | 0.3% |
| 2022 | Trimble Co 05 | 402 | 421 | 1.3% | 1.3% |
| 2022 | Trimble Co 06 | 311 | 352 | 1.0% | 1.1% |
| 2022 | Trimble Co 07 | 249 | 308 | 0.8% | 1.0% |
| 2022 | Trimble Co 08 | 45 | 95 | 0.1% | 0.3% |
| 2022 | Trimble Co 09 | 188 | 238 | 0.6% | 0.7% |
| 2022 | Trimble Co 10 | 24 | 67 | 0.1% | 0.2% |
| 2022 | OVEC | 544 | 958 | 1.7% | 3.0% |
| 2022 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2022 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2022 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2022 | Purchases | 27 | 0 | 0.1% | 0.0% |
| 2022 | Ragland Solar PPA | 0 | 0 | 0.0% | 0.0% |
| 2022 | Rhudes Creek Solar PPA | 0 | 0 | 0.0% | 0.0% |
| 2022 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2022 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2023 | Brown 3 | 932 | 991 | 2.9% | 3.1% |
| 2023 | Ghent 1 | 2,793 | 3,018 | 8.8% | 9.4% |
| 2023 | Ghent 2 | 2,811 | 2,855 | 8.8% | 8.9% |
| 2023 | Ghent 3 | 2,335 | 2,578 | 7.3% | 8.0% |
| 2023 | Ghent 4 | 2,246 | 2,449 | 7.0% | 7.6% |
| 2023 | Mill Creek 1 | 1,885 | 1,775 | 5.9% | 5.5% |
| 2023 | Mill Creek 2 | 792 | 814 | 2.5% | 2.5% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2023 | Mill Creek 3 | 2,292 | 1,900 | 7.2% | 5.9% |
| 2023 | Mill Creek 4 | 3,052 | 2,925 | 9.6% | 9.1% |
| 2023 | Trimble County 1 | 2,456 | 2,407 | 7.7% | 7.5% |
| 2023 | Trimble County 2 | 2,671 | 2,978 | 8.4% | 9.3% |
| 2023 | Cane Run 7 2X1 | 5,378 | 4,782 | 16.9% | 14.9% |
| 2023 | Brown 5 | 164 | 54 | 0.5% | 0.2% |
| 2023 | Brown 6 | 92 | 88 | 0.3% | 0.3% |
| 2023 | Brown 7 | 62 | 66 | 0.2% | 0.2% |
| 2023 | Brown 8 | 13 | 8 | 0.0% | 0.0% |
| 2023 | Brown 9 | 21 | 19 | 0.1% | 0.1% |
| 2023 | Brown 10 | 34 | 14 | 0.1% | 0.0% |
| 2023 | Brown 11 | 6 | 4 | 0.0% | 0.0% |
| 2023 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 13 | 40 | 42 | 0.1% | 0.1% |
| 2023 | Trimble Co 05 | 304 | 340 | 1.0% | 1.1% |
| 2023 | Trimble Co 06 | 211 | 274 | 0.7% | 0.9% |
| 2023 | Trimble Co 07 | 185 | 236 | 0.6% | 0.7% |
| 2023 | Trimble Co 08 | 34 | 69 | 0.1% | 0.2% |
| 2023 | Trimble Co 09 | 130 | 176 | 0.4% | 0.5% |
| 2023 | Trimble Co 10 | 15 | 40 | 0.0% | 0.1% |
| 2023 | OVEC | 519 | 550 | 1.6% | 1.7% |
| 2023 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2023 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2023 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2023 | Purchases | 29 | 0 | 0.1% | 0.0% |
| 2023 | Ragland Solar PPA | 0 | 0 | 0.0% | 0.0% |
| 2023 | Rhudes Creek Solar PPA | 0 | 225 | 0.0% | 0.7% |
| 2023 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2023 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2024 | Brown 3 | 917 | 1,106 | 2.9% | 3.5% |
| 2024 | Ghent 1 | 2,681 | 2,684 | 8.4% | 8.4% |
| 2024 | Ghent 2 | 2,457 | 2,328 | 7.7% | 7.3% |
| 2024 | Ghent 3 | 2,326 | 2,433 | 7.3% | 7.6% |
| 2024 | Ghent 4 | 2,117 | 1,929 | 6.6% | 6.0% |
| 2024 | Mill Creek 1 | 2,153 | 2,106 | 6.7% | 6.6% |
| 2024 | Mill Creek 2 | 829 | 931 | 2.6% | 2.9% |
| 2024 | Mill Creek 3 | 2,783 | 2,510 | 8.7% | 7.8% |
| 2024 | Mill Creek 4 | 3,076 | 3,097 | 9.6% | 9.7% |
| 2024 | Trimble County 1 | 2,626 | 2,509 | 8.2% | 7.8% |
| 2024 | Trimble County 2 | 3,039 | 3,191 | 9.5% | 10.0% |
| 2024 | Cane Run 7 2X1 | 4,633 | 4,632 | 14.5% | 14.5% |
| 2024 | Brown 5 | 141 | 72 | 0.4% | 0.2% |
| 2024 | Brown 6 | 82 | 99 | 0.3% | 0.3% |
| 2024 | Brown 7 | 59 | 69 | 0.2% | 0.2% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2024 | Brown 8 | 12 | 5 | 0.0% | 0.0% |
| 2024 | Brown 9 | 21 | 9 | 0.1% | 0.0% |
| 2024 | Brown 10 | 30 | 8 | 0.1% | 0.0% |
| 2024 | Brown 11 | 7 | 3 | 0.0% | 0.0% |
| 2024 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2024 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2024 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2024 | Paddys Run 13 | 45 | 38 | 0.1% | 0.1% |
| 2024 | Trimble Co 05 | 352 | 370 | 1.1% | 1.2% |
| 2024 | Trimble Co 06 | 262 | 292 | 0.8% | 0.9% |
| 2024 | Trimble Co 07 | 170 | 177 | 0.5% | 0.6% |
| 2024 | Trimble Co 08 | 34 | 61 | 0.1% | 0.2% |
| 2024 | Trimble Co 09 | 129 | 156 | 0.4% | 0.5% |
| 2024 | Trimble Co 10 | 21 | 32 | 0.1% | 0.1% |
| 2024 | OVEC | 530 | 567 | 1.7% | 1.8% |
| 2024 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2024 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2024 | Ohio Falls | 301 | 295 | 0.9% | 0.9% |
| 2024 | Purchases | 20 | 0 | 0.1% | 0.0% |
| 2024 | Ragland Solar PPA | 0 | 0 | 0.0% | 0.0% |
| 2024 | Rhudes Creek Solar PPA | 0 | 223 | 0.0% | 0.7% |
| 2024 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2024 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2025 | Brown 3 | 785 | 929 | 2.5% | 2.9% |
| 2025 | Ghent 1 | 2,490 | 2,482 | 7.8% | 7.8% |
| 2025 | Ghent 2 | 2,697 | 2,660 | 8.5% | 8.4% |
| 2025 | Ghent 3 | 2,274 | 2,384 | 7.1% | 7.5% |
| 2025 | Ghent 4 | 2,239 | 1,963 | 7.0% | 6.2% |
| 2025 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Mill Creek 2 | 2,098 | 2,043 | 6.6% | 6.4% |
| 2025 | Mill Creek 3 | 2,563 | 2,348 | 8.0% | 7.4% |
| 2025 | Mill Creek 4 | 3,391 | 3,410 | 10.6% | 10.7% |
| 2025 | Trimble County 1 | 2,314 | 2,196 | 7.3% | 6.9% |
| 2025 | Trimble County 2 | 3,029 | 3,154 | 9.5% | 9.9% |
| 2025 | Cane Run 7 2X1 | 5,407 | 5,243 | 17.0% | 16.5% |
| 2025 | Brown 5 | 168 | 95 | 0.5% | 0.3% |
| 2025 | Brown 6 | 89 | 100 | 0.3% | 0.3% |
| 2025 | Brown 7 | 56 | 82 | 0.2% | 0.3% |
| 2025 | Brown 8 | 7 | 7 | 0.0% | 0.0% |
| 2025 | Brown 9 | 19 | 10 | 0.1% | 0.0% |
| 2025 | Brown 10 | 34 | 10 | 0.1% | 0.0% |
| 2025 | Brown 11 | 3 | 3 | 0.0% | 0.0% |
| 2025 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 13 | 36 | 37 | 0.1% | 0.1% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2025 | Trimble Co 05 | 452 | 353 | 1.4% | 1.1% |
| 2025 | Trimble Co 06 | 330 | 277 | 1.0% | 0.9% |
| 2025 | Trimble Co 07 | 237 | 213 | 0.7% | 0.7% |
| 2025 | Trimble Co 08 | 31 | 51 | 0.1% | 0.2% |
| 2025 | Trimble Co 09 | 137 | 127 | 0.4% | 0.4% |
| 2025 | Trimble Co 10 | 14 | 31 | 0.0% | 0.1% |
| 2025 | OVEC | 538 | 628 | 1.7% | 2.0% |
| 2025 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2025 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2025 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2025 | Purchases | 18 | 0 | 0.1% | 0.0% |
| 2025 | Ragland Solar PPA | 0 | 377 | 0.0% | 1.2% |
| 2025 | Rhudes Creek Solar PPA | 0 | 222 | 0.0% | 0.7% |
| 2025 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2025 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2026 | Brown 3 | 734 | 921 | 2.3% | 2.9% |
| 2026 | Ghent 1 | 2,669 | 2,726 | 8.4% | 8.6% |
| 2026 | Ghent 2 | 2,659 | 2,567 | 8.4% | 8.1% |
| 2026 | Ghent 3 | 2,171 | 2,211 | 6.8% | 7.0% |
| 2026 | Ghent 4 | 2,139 | 1,896 | 6.7% | 6.0% |
| 2026 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Mill Creek 2 | 1,858 | 1,984 | 5.8% | 6.3% |
| 2026 | Mill Creek 3 | 2,795 | 2,550 | 8.8% | 8.1% |
| 2026 | Mill Creek 4 | 3,132 | 3,393 | 9.9% | 10.7% |
| 2026 | Trimble County 1 | 2,636 | 2,465 | 8.3% | 7.8% |
| 2026 | Trimble County 2 | 2,713 | 2,894 | 8.5% | 9.1% |
| 2026 | Cane Run 7 2X1 | 5,287 | 5,181 | 16.6% | 16.4% |
| 2026 | Brown 5 | 192 | 92 | 0.6% | 0.3% |
| 2026 | Brown 6 | 118 | 120 | 0.4% | 0.4% |
| 2026 | Brown 7 | 94 | 90 | 0.3% | 0.3% |
| 2026 | Brown 8 | 12 | 10 | 0.0% | 0.0% |
| 2026 | Brown 9 | 33 | 18 | 0.1% | 0.1% |
| 2026 | Brown 10 | 21 | 17 | 0.1% | 0.1% |
| 2026 | Brown 11 | 8 | 8 | 0.0% | 0.0% |
| 2026 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 13 | 47 | 21 | 0.1% | 0.1% |
| 2026 | Trimble Co 05 | 494 | 293 | 1.6% | 0.9% |
| 2026 | Trimble Co 06 | 399 | 207 | 1.3% | 0.7% |
| 2026 | Trimble Co 07 | 303 | 179 | 1.0% | 0.6% |
| 2026 | Trimble Co 08 | 47 | 52 | 0.1% | 0.2% |
| 2026 | Trimble Co 09 | 249 | 120 | 0.8% | 0.4% |
| 2026 | Trimble Co 10 | 30 | 27 | 0.1% | 0.1% |
| 2026 | OVEC | 533 | 601 | 1.7% | 1.9% |
| 2026 | Brown Solar | 18 | 17 | 0.1% | 0.1% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2026 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2026 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2026 | Purchases | 15 | 0 | 0.0% | 0.0% |
| 2026 | Ragland Solar PPA | 0 | 376 | 0.0% | 1.2% |
| 2026 | Rhudes Creek Solar PPA | 0 | 222 | 0.0% | 0.7% |
| 2026 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2026 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2027 | Brown 3 | 662 | 944 | 2.1% | 3.0% |
| 2027 | Ghent 1 | 2,661 | 2,658 | 8.4% | 8.4% |
| 2027 | Ghent 2 | 2,356 | 2,319 | 7.4% | 7.4% |
| 2027 | Ghent 3 | 2,352 | 2,336 | 7.4% | 7.4% |
| 2027 | Ghent 4 | 2,144 | 1,991 | 6.8% | 6.3% |
| 2027 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Mill Creek 2 | 2,105 | 2,085 | 6.6% | 6.6% |
| 2027 | Mill Creek 3 | 2,395 | 2,160 | 7.5% | 6.9% |
| 2027 | Mill Creek 4 | 3,359 | 3,055 | 10.6% | 9.7% |
| 2027 | Trimble County 1 | 2,537 | 2,420 | 8.0% | 7.7% |
| 2027 | Trimble County 2 | 3,024 | 3,268 | 9.5% | 10.4% |
| 2027 | Cane Run 7 2X1 | 5,411 | 5,341 | 17.1% | 16.9% |
| 2027 | Brown 5 | 157 | 97 | 0.5% | 0.3% |
| 2027 | Brown 6 | 121 | 87 | 0.4% | 0.3% |
| 2027 | Brown 7 | 99 | 64 | 0.3% | 0.2% |
| 2027 | Brown 8 | 14 | 17 | 0.0% | 0.1% |
| 2027 | Brown 9 | 32 | 11 | 0.1% | 0.0% |
| 2027 | Brown 10 | 23 | 22 | 0.1% | 0.1% |
| 2027 | Brown 11 | 11 | 11 | 0.0% | 0.0% |
| 2027 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 13 | 82 | 19 | 0.3% | 0.1% |
| 2027 | Trimble Co 05 | 429 | 333 | 1.4% | 1.1% |
| 2027 | Trimble Co 06 | 238 | 262 | 0.8% | 0.8% |
| 2027 | Trimble Co 07 | 302 | 201 | 1.0% | 0.6% |
| 2027 | Trimble Co 08 | 57 | 51 | 0.2% | 0.2% |
| 2027 | Trimble Co 09 | 181 | 139 | 0.6% | 0.4% |
| 2027 | Trimble Co 10 | 30 | 32 | 0.1% | 0.1% |
| 2027 | OVEC | 526 | 613 | 1.7% | 1.9% |
| 2027 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2027 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2027 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2027 | Purchases | 17 | 0 | 0.1% | 0.0% |
| 2027 | Ragland Solar PPA | 0 | 373 | 0.0% | 1.2% |
| 2027 | Rhudes Creek Solar PPA | 0 | 219 | 0.0% | 0.7% |
| 2027 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2027 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2027 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New Solar | 0 | 0 | 0.0% | 0.0% |
| 2028 | Brown 3 | 703 | 0 | 2.2% | 0.0% |
| 2028 | Ghent 1 | 2,657 | 2,779 | 8.4% | 8.8% |
| 2028 | Ghent 2 | 2,696 | 2,687 | 8.5% | 8.5% |
| 2028 | Ghent 3 | 2,467 | 2,554 | 7.8% | 8.1% |
| 2028 | Ghent 4 | 1,969 | 1,982 | 6.2% | 6.3% |
| 2028 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Mill Creek 2 | 2,016 | 0 | 6.4% | 0.0% |
| 2028 | Mill Creek 3 | 2,811 | 2,626 | 8.9% | 8.3% |
| 2028 | Mill Creek 4 | 3,058 | 3,110 | 9.6% | 9.9% |
| 2028 | Trimble County 1 | 2,684 | 2,568 | 8.5% | 8.1% |
| 2028 | Trimble County 2 | 3,090 | 3,383 | 9.7% | 10.7% |
| 2028 | Cane Run 7 2X1 | 4,643 | 4,541 | 14.6% | 14.4% |
| 2028 | Brown 5 | 134 | 194 | 0.4% | 0.6% |
| 2028 | Brown 6 | 117 | 97 | 0.4% | 0.3% |
| 2028 | Brown 7 | 97 | 75 | 0.3% | 0.2% |
| 2028 | Brown 8 | 26 | 49 | 0.1% | 0.2% |
| 2028 | Brown 9 | 21 | 64 | 0.1% | 0.2% |
| 2028 | Brown 10 | 15 | 34 | 0.0% | 0.1% |
| 2028 | Brown 11 | 9 | 24 | 0.0% | 0.1% |
| 2028 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 13 | 99 | 52 | 0.3% | 0.2% |
| 2028 | Trimble Co 05 | 394 | 366 | 1.2% | 1.2% |
| 2028 | Trimble Co 06 | 406 | 267 | 1.3% | 0.8% |
| 2028 | Trimble Co 07 | 348 | 236 | 1.1% | 0.7% |
| 2028 | Trimble Co 08 | 40 | 24 | 0.1% | 0.1% |
| 2028 | Trimble Co 09 | 258 | 173 | 0.8% | 0.6% |
| 2028 | Trimble Co 10 | 20 | 8 | 0.1% | 0.0% |
| 2028 | OVEC | 538 | 597 | 1.7% | 1.9% |
| 2028 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2028 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2028 | Ohio Falls | 301 | 295 | 0.9% | 0.9% |
| 2028 | Purchases | 15 | 0 | 0.0% | 0.0% |
| 2028 | Ragland Solar PPA | 0 | 372 | 0.0% | 1.2% |
| 2028 | Rhudes Creek Solar PPA | 0 | 218 | 0.0% | 0.7% |
| 2028 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2028 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 1 | 0 | 495 | 0.0% | 1.6% |
| 2028 | New SCCT 2 | 0 | 340 | 0.0% | 1.1% |
| 2028 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New Solar | 0 | 1,199 | 0.0% | 3.8% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2029 | Brown 3 | 584 | 0 | 1.8% | 0.0% |
| 2029 | Ghent 1 | 2,334 | 2,444 | 7.4% | 7.8% |
| 2029 | Ghent 2 | 2,569 | 2,650 | 8.1% | 8.4% |
| 2029 | Ghent 3 | 2,388 | 2,531 | 7.5% | 8.1% |
| 2029 | Ghent 4 | 2,117 | 2,032 | 6.7% | 6.5% |
| 2029 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Mill Creek 2 | 1,502 | 0 | 4.7% | 0.0% |
| 2029 | Mill Creek 3 | 2,569 | 2,384 | 8.1% | 7.6% |
| 2029 | Mill Creek 4 | 3,329 | 3,449 | 10.5% | 11.0% |
| 2029 | Trimble County 1 | 2,542 | 2,424 | 8.0% | 7.7% |
| 2029 | Trimble County 2 | 3,032 | 3,314 | 9.6% | 10.6% |
| 2029 | Cane Run 7 2X1 | 5,374 | 5,325 | 17.0% | 17.0% |
| 2029 | Brown 5 | 60 | 161 | 0.2% | 0.5% |
| 2029 | Brown 6 | 68 | 71 | 0.2% | 0.2% |
| 2029 | Brown 7 | 47 | 53 | 0.1% | 0.2% |
| 2029 | Brown 8 | 5 | 38 | 0.0% | 0.1% |
| 2029 | Brown 9 | 7 | 63 | 0.0% | 0.2% |
| 2029 | Brown 10 | 5 | 33 | 0.0% | 0.1% |
| 2029 | Brown 11 | 3 | 14 | 0.0% | 0.0% |
| 2029 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 13 | 57 | 43 | 0.2% | 0.1% |
| 2029 | Trimble Co 05 | 395 | 256 | 1.3% | 0.8% |
| 2029 | Trimble Co 06 | 315 | 93 | 1.0% | 0.3% |
| 2029 | Trimble Co 07 | 248 | 183 | 0.8% | 0.6% |
| 2029 | Trimble Co 08 | 20 | 15 | 0.1% | 0.0% |
| 2029 | Trimble Co 09 | 180 | 112 | 0.6% | 0.4% |
| 2029 | Trimble Co 10 | 10 | 8 | 0.0% | 0.0% |
| 2029 | OVEC | 523 | 600 | 1.7% | 1.9% |
| 2029 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2029 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2029 | Ohio Falls | 300 | 294 | 0.9% | 0.9% |
| 2029 | Purchases | 13 | 0 | 0.0% | 0.0% |
| 2029 | Ragland Solar PPA | 0 | 373 | 0.0% | 1.2% |
| 2029 | Rhudes Creek Solar PPA | 0 | 216 | 0.0% | 0.7% |
| 2029 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2029 | New NGCC 1 | 929 | 0 | 2.9% | 0.0% |
| 2029 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 1 | 0 | 524 | 0.0% | 1.7% |
| 2029 | New SCCT 2 | 0 | 363 | 0.0% | 1.2% |
| 2029 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New Solar | 0 | 1,196 | 0.0% | 3.8% |
| 2030 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Ghent 1 | 2,543 | 2,676 | 8.1% | 8.6% |
| 2030 | Ghent 2 | 2,436 | 2,486 | 7.7% | 7.9% |
| 2030 | Ghent 3 | 2,176 | 2,343 | 6.9% | 7.5% |
| 2030 | Ghent 4 | 2,067 | 2,119 | 6.6% | 6.8% |
| 2030 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Mill Creek 3 | 2,762 | 2,652 | 8.8% | 8.5% |

| Year | Unit | Generation (GWh) Case Nos 2020-00349 and 00350 | Generation (GWh) 2021 IRP Base Load, Base Fuel | Percentage Contribution To Annual Total Case Nos 2020-00349 and 00350 | Percentage Contribution To Annual Total 2021 IRP Base Load, Base Fuel |
|---|---|---|---|---|---|
| 2030 | Mill Creek 4 | 2,871 | 2,927 | 9.1% | 9.4% |
| 2030 | Trimble County 1 | 2,620 | 2,532 | 8.3% | 8.1% |
| 2030 | Trimble County 2 | 2,979 | 3,272 | 9.5% | 10.5% |
| 2030 | Cane Run 7 2X1 | 5,264 | 5,253 | 16.7% | 16.8% |
| 2030 | Brown 5 | 50 | 154 | 0.2% | 0.5% |
| 2030 | Brown 6 | 87 | 59 | 0.3% | 0.2% |
| 2030 | Brown 7 | 59 | 47 | 0.2% | 0.1% |
| 2030 | Brown 8 | 9 | 37 | 0.0% | 0.1% |
| 2030 | Brown 9 | 13 | 49 | 0.0% | 0.2% |
| 2030 | Brown 10 | 9 | 35 | 0.0% | 0.1% |
| 2030 | Brown 11 | 4 | 10 | 0.0% | 0.0% |
| 2030 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 13 | 80 | 38 | 0.3% | 0.1% |
| 2030 | Trimble Co 05 | 422 | 296 | 1.3% | 0.9% |
| 2030 | Trimble Co 06 | 346 | 260 | 1.1% | 0.8% |
| 2030 | Trimble Co 07 | 268 | 205 | 0.9% | 0.7% |
| 2030 | Trimble Co 08 | 33 | 23 | 0.1% | 0.1% |
| 2030 | Trimble Co 09 | 189 | 135 | 0.6% | 0.4% |
| 2030 | Trimble Co 10 | 15 | 14 | 0.0% | 0.0% |
| 2030 | OVEC | 536 | 606 | 1.7% | 1.9% |
| 2030 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2030 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2030 | Ohio Falls | 300 | 294 | 1.0% | 0.9% |
| 2030 | Purchases | 14 | 0 | 0.0% | 0.0% |
| 2030 | Ragland Solar PPA | 0 | 371 | 0.0% | 1.2% |
| 2030 | Rhudes Creek Solar PPA | 0 | 216 | 0.0% | 0.7% |
| 2030 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2030 | New NGCC 1 | 3,256 | 0 | 10.3% | 0.0% |
| 2030 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 1 | 0 | 497 | 0.0% | 1.6% |
| 2030 | New SCCT 2 | 0 | 367 | 0.0% | 1.2% |
| 2030 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New Solar | 0 | 1,196 | 0.0% | 3.8% |
| 2031 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Ghent 1 | 2,607 | 2,752 | 8.3% | 8.8% |
| 2031 | Ghent 2 | 2,577 | 2,600 | 8.2% | 8.3% |
| 2031 | Ghent 3 | 2,301 | 2,450 | 7.3% | 7.8% |
| 2031 | Ghent 4 | 2,074 | 2,069 | 6.6% | 6.6% |
| 2031 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Mill Creek 3 | 2,600 | 2,455 | 8.3% | 7.9% |
| 2031 | Mill Creek 4 | 3,275 | 3,420 | 10.4% | 10.9% |
| 2031 | Trimble County 1 | 2,433 | 2,344 | 7.7% | 7.5% |
| 2031 | Trimble County 2 | 2,998 | 3,252 | 9.5% | 10.4% |
| 2031 | Cane Run 7 2X1 | 5,210 | 5,228 | 16.5% | 16.7% |
| 2031 | Brown 5 | 34 | 86 | 0.1% | 0.3% |
| 2031 | Brown 6 | 75 | 76 | 0.2% | 0.2% |
| 2031 | Brown 7 | 58 | 50 | 0.2% | 0.2% |
| 2031 | Brown 8 | 9 | 9 | 0.0% | 0.0% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2031 | Brown 9 | 20 | 14 | 0.1% | 0.0% |
| 2031 | Brown 10 | 12 | 10 | 0.0% | 0.0% |
| 2031 | Brown 11 | 4 | 5 | 0.0% | 0.0% |
| 2031 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 13 | 68 | 36 | 0.2% | 0.1% |
| 2031 | Trimble Co 05 | 329 | 267 | 1.0% | 0.9% |
| 2031 | Trimble Co 06 | 269 | 215 | 0.9% | 0.7% |
| 2031 | Trimble Co 07 | 220 | 166 | 0.7% | 0.5% |
| 2031 | Trimble Co 08 | 27 | 18 | 0.1% | 0.1% |
| 2031 | Trimble Co 09 | 159 | 122 | 0.5% | 0.4% |
| 2031 | Trimble Co 10 | 16 | 10 | 0.1% | 0.0% |
| 2031 | OVEC | 534 | 593 | 1.7% | 1.9% |
| 2031 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2031 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2031 | Ohio Falls | 300 | 294 | 1.0% | 0.9% |
| 2031 | Purchases | 16 | 0 | 0.0% | 0.0% |
| 2031 | Ragland Solar PPA | 0 | 367 | 0.0% | 1.2% |
| 2031 | Rhudes Creek Solar PPA | 0 | 216 | 0.0% | 0.7% |
| 2031 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2031 | New NGCC 1 | 3,173 | 0 | 10.1% | 0.0% |
| 2031 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 1 | 0 | 490 | 0.0% | 1.6% |
| 2031 | New SCCT 2 | 0 | 324 | 0.0% | 1.0% |
| 2031 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New Solar | 0 | 1,196 | 0.0% | 3.8% |
| 2032 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Ghent 1 | 2,607 | 2,688 | 8.3% | 8.6% |
| 2032 | Ghent 2 | 2,638 | 2,681 | 8.4% | 8.6% |
| 2032 | Ghent 3 | 2,268 | 2,491 | 7.2% | 8.0% |
| 2032 | Ghent 4 | 2,052 | 2,119 | 6.5% | 6.8% |
| 2032 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Mill Creek 3 | 2,782 | 2,635 | 8.8% | 8.4% |
| 2032 | Mill Creek 4 | 3,119 | 3,227 | 9.9% | 10.3% |
| 2032 | Trimble County 1 | 2,598 | 2,532 | 8.3% | 8.1% |
| 2032 | Trimble County 2 | 3,001 | 3,280 | 9.5% | 10.5% |
| 2032 | Cane Run 7 2X1 | 4,894 | 4,856 | 15.5% | 15.5% |
| 2032 | Brown 5 | 30 | 88 | 0.1% | 0.3% |
| 2032 | Brown 6 | 75 | 72 | 0.2% | 0.2% |
| 2032 | Brown 7 | 54 | 52 | 0.2% | 0.2% |
| 2032 | Brown 8 | 9 | 8 | 0.0% | 0.0% |
| 2032 | Brown 9 | 13 | 12 | 0.0% | 0.0% |
| 2032 | Brown 10 | 9 | 8 | 0.0% | 0.0% |
| 2032 | Brown 11 | 3 | 3 | 0.0% | 0.0% |
| 2032 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 13 | 77 | 46 | 0.2% | 0.1% |
| 2032 | Trimble Co 05 | 339 | 320 | 1.1% | 1.0% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2032 | Trimble Co 06 | 270 | 259 | 0.9% | 0.8% |
| 2032 | Trimble Co 07 | 205 | 214 | 0.7% | 0.7% |
| 2032 | Trimble Co 08 | 30 | 26 | 0.1% | 0.1% |
| 2032 | Trimble Co 09 | 155 | 143 | 0.5% | 0.5% |
| 2032 | Trimble Co 10 | 18 | 12 | 0.1% | 0.0% |
| 2032 | OVEC | 544 | 603 | 1.7% | 1.9% |
| 2032 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2032 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2032 | Ohio Falls | 301 | 295 | 1.0% | 0.9% |
| 2032 | Purchases | 14 | 0 | 0.0% | 0.0% |
| 2032 | Ragland Solar PPA | 0 | 369 | 0.0% | 1.2% |
| 2032 | Rhudes Creek Solar PPA | 0 | 214 | 0.0% | 0.7% |
| 2032 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2032 | New NGCC 1 | 3,267 | 0 | 10.4% | 0.0% |
| 2032 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 1 | 0 | 429 | 0.0% | 1.4% |
| 2032 | New SCCT 2 | 0 | 297 | 0.0% | 1.0% |
| 2032 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New Solar | 0 | 1,199 | 0.0% | 3.8% |
| 2033 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Ghent 1 | 2,632 | 2,775 | 8.4% | 8.9% |
| 2033 | Ghent 2 | 2,571 | 2,623 | 8.2% | 8.4% |
| 2033 | Ghent 3 | 2,320 | 2,504 | 7.4% | 8.0% |
| 2033 | Ghent 4 | 2,134 | 2,128 | 6.8% | 6.8% |
| 2033 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Mill Creek 3 | 2,575 | 2,456 | 8.2% | 7.9% |
| 2033 | Mill Creek 4 | 3,294 | 3,396 | 10.5% | 10.9% |
| 2033 | Trimble County 1 | 2,257 | 2,157 | 7.2% | 6.9% |
| 2033 | Trimble County 2 | 3,001 | 3,232 | 9.5% | 10.4% |
| 2033 | Cane Run 7 2X1 | 5,094 | 5,073 | 16.2% | 16.3% |
| 2033 | Brown 5 | 26 | 108 | 0.1% | 0.3% |
| 2033 | Brown 6 | 94 | 34 | 0.3% | 0.1% |
| 2033 | Brown 7 | 64 | 27 | 0.2% | 0.1% |
| 2033 | Brown 8 | 7 | 7 | 0.0% | 0.0% |
| 2033 | Brown 9 | 13 | 14 | 0.0% | 0.0% |
| 2033 | Brown 10 | 12 | 8 | 0.0% | 0.0% |
| 2033 | Brown 11 | 7 | 2 | 0.0% | 0.0% |
| 2033 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2033 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Paddys Run 13 | 87 | 51 | 0.3% | 0.2% |
| 2033 | Trimble Co 05 | 360 | 341 | 1.1% | 1.1% |
| 2033 | Trimble Co 06 | 305 | 296 | 1.0% | 0.9% |
| 2033 | Trimble Co 07 | 235 | 209 | 0.7% | 0.7% |
| 2033 | Trimble Co 08 | 39 | 26 | 0.1% | 0.1% |
| 2033 | Trimble Co 09 | 175 | 151 | 0.6% | 0.5% |
| 2033 | Trimble Co 10 | 21 | 13 | 0.1% | 0.0% |
| 2033 | OVEC | 543 | 606 | 1.7% | 1.9% |
| 2033 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2033 | Dix Dam | 90 | 94 | 0.3% | 0.3% |

| | | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| Year | Unit | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2033 | Ohio Falls | 300 | 294 | 1.0% | 0.9% |
| 2033 | Purchases | 15 | 0 | 0.0% | 0.0% |
| 2033 | Ragland Solar PPA | 0 | 367 | 0.0% | 1.2% |
| 2033 | Rhudes Creek Solar PPA | 0 | 214 | 0.0% | 0.7% |
| 2033 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2033 | New NGCC 1 | 3,163 | 0 | 10.1% | 0.0% |
| 2033 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 1 | 0 | 454 | 0.0% | 1.5% |
| 2033 | New SCCT 2 | 0 | 324 | 0.0% | 1.0% |
| 2033 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New Solar | 0 | 1,196 | 0.0% | 3.8% |
| 2034 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Ghent 1 | 781 | 0 | 2.5% | 0.0% |
| 2034 | Ghent 2 | 937 | 0 | 3.0% | 0.0% |
| 2034 | Ghent 3 | 2,209 | 2,455 | 7.0% | 7.8% |
| 2034 | Ghent 4 | 1,988 | 2,217 | 6.3% | 7.1% |
| 2034 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Mill Creek 3 | 2,521 | 2,444 | 8.0% | 7.8% |
| 2034 | Mill Creek 4 | 2,882 | 2,964 | 9.1% | 9.5% |
| 2034 | Trimble County 1 | 2,562 | 2,521 | 8.1% | 8.0% |
| 2034 | Trimble County 2 | 2,594 | 2,934 | 8.2% | 9.4% |
| 2034 | Cane Run 7 2X1 | 5,283 | 4,956 | 16.7% | 15.8% |
| 2034 | Brown 5 | 15 | 56 | 0.0% | 0.2% |
| 2034 | Brown 6 | 69 | 115 | 0.2% | 0.4% |
| 2034 | Brown 7 | 49 | 94 | 0.2% | 0.3% |
| 2034 | Brown 8 | 8 | 1 | 0.0% | 0.0% |
| 2034 | Brown 9 | 7 | 0 | 0.0% | 0.0% |
| 2034 | Brown 10 | 5 | 43 | 0.0% | 0.1% |
| 2034 | Brown 11 | 3 | 1 | 0.0% | 0.0% |
| 2034 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 13 | 71 | 52 | 0.2% | 0.2% |
| 2034 | Trimble Co 05 | 313 | 385 | 1.0% | 1.2% |
| 2034 | Trimble Co 06 | 248 | 344 | 0.8% | 1.1% |
| 2034 | Trimble Co 07 | 187 | 294 | 0.6% | 0.9% |
| 2034 | Trimble Co 08 | 25 | 8 | 0.1% | 0.0% |
| 2034 | Trimble Co 09 | 148 | 232 | 0.5% | 0.7% |
| 2034 | Trimble Co 10 | 14 | 5 | 0.0% | 0.0% |
| 2034 | OVEC | 535 | 616 | 1.7% | 2.0% |
| 2034 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2034 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2034 | Ohio Falls | 300 | 275 | 1.0% | 0.9% |
| 2034 | Purchases | 14 | 0 | 0.0% | 0.0% |
| 2034 | Ragland Solar PPA | 0 | 362 | 0.0% | 1.2% |
| 2034 | Rhudes Creek Solar PPA | 0 | 213 | 0.0% | 0.7% |
| 2034 | New Battery Storage | 0 | 0 | 0.0% | 0.0% |
| 2034 | New NGCC 1 | 3,310 | 0 | 10.5% | 0.0% |
| 2034 | New NGCC 2 | 2,248 | 0 | 7.1% | 0.0% |
| 2034 | New NGCC 3 | 2,119 | 0 | 6.7% | 0.0% |

| Year | Unit | Generation (GWh) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2034 | New SCCT 1 | 0 | 812 | 0.0% | 2.6% |
| 2034 | New SCCT 2 | 0 | 656 | 0.0% | 2.1% |
| 2034 | New SCCT 3 | 0 | 479 | 0.0% | 1.5% |
| 2034 | New SCCT 4 | 0 | 338 | 0.0% | 1.1% |
| 2034 | New SCCT 5 | 0 | 221 | 0.0% | 0.7% |
| 2034 | New SCCT 6 | 0 | 123 | 0.0% | 0.4% |
| 2034 | New Solar | 0 | 5,022 | 0.0% | 16.0% |
| 2035 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 1 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 2 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 3 | 2,154 | 2,463 | 6.8% | 7.9% |
| 2035 | Ghent 4 | 1,873 | 2,261 | 5.9% | 7.2% |
| 2035 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Mill Creek 3 | 2,167 | 2,188 | 6.9% | 7.0% |
| 2035 | Mill Creek 4 | 2,956 | 3,244 | 9.4% | 10.4% |
| 2035 | Trimble County 1 | 2,350 | 2,392 | 7.5% | 7.6% |
| 2035 | Trimble County 2 | 2,842 | 3,254 | 9.0% | 10.4% |
| 2035 | Cane Run 7 2X1 | 4,511 | 4,318 | 14.3% | 13.8% |
| 2035 | Brown 5 | 28 | 66 | 0.1% | 0.2% |
| 2035 | Brown 6 | 90 | 104 | 0.3% | 0.3% |
| 2035 | Brown 7 | 72 | 75 | 0.2% | 0.2% |
| 2035 | Brown 8 | 18 | 0 | 0.1% | 0.0% |
| 2035 | Brown 9 | 10 | 0 | 0.0% | 0.0% |
| 2035 | Brown 10 | 9 | 0 | 0.0% | 0.0% |
| 2035 | Brown 11 | 7 | 1 | 0.0% | 0.0% |
| 2035 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 13 | 89 | 60 | 0.3% | 0.2% |
| 2035 | Trimble Co 05 | 362 | 453 | 1.1% | 1.4% |
| 2035 | Trimble Co 06 | 296 | 397 | 0.9% | 1.3% |
| 2035 | Trimble Co 07 | 237 | 343 | 0.8% | 1.1% |
| 2035 | Trimble Co 08 | 39 | 13 | 0.1% | 0.0% |
| 2035 | Trimble Co 09 | 197 | 276 | 0.6% | 0.9% |
| 2035 | Trimble Co 10 | 27 | 7 | 0.1% | 0.0% |
| 2035 | OVEC | 543 | 615 | 1.7% | 2.0% |
| 2035 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2035 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2035 | Ohio Falls | 300 | 279 | 1.0% | 0.9% |
| 2035 | Purchases | 15 | 0 | 0.0% | 0.0% |
| 2035 | Ragland Solar PPA | 0 | 364 | 0.0% | 1.2% |
| 2035 | Rhudes Creek Solar PPA | 0 | 212 | 0.0% | 0.7% |
| 2035 | New Battery Storage | 0 | 7 | 0.0% | 0.0% |
| 2035 | New NGCC 1 | 3,541 | 0 | 11.2% | 0.0% |
| 2035 | New NGCC 2 | 3,444 | 0 | 10.9% | 0.0% |
| 2035 | New NGCC 3 | 3,249 | 0 | 10.3% | 0.0% |
| 2035 | New SCCT 1 | 0 | 846 | 0.0% | 2.7% |
| 2035 | New SCCT 2 | 0 | 667 | 0.0% | 2.1% |
| 2035 | New SCCT 3 | 0 | 506 | 0.0% | 1.6% |
| 2035 | New SCCT 4 | 0 | 375 | 0.0% | 1.2% |
| 2035 | New SCCT 5 | 0 | 264 | 0.0% | 0.8% |
| 2035 | New SCCT 6 | 0 | 149 | 0.0% | 0.5% |
| 2035 | New Solar | 0 | 5,022 | 0.0% | 16.0% |
| 2036 | Brown 3 | 0 | 0 | 0.0% | 0.0% |

| Year | Unit | Generation (GWh) Case Nos 2020-00349 and 00350 | Generation (GWh) 2021 IRP Base Load, Base Fuel | Percentage Contribution To Annual Total Case Nos 2020-00349 and 00350 | Percentage Contribution To Annual Total 2021 IRP Base Load, Base Fuel |
|---|---|---|---|---|---|
| 2036 | Ghent 1 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Ghent 2 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Ghent 3 | 2,043 | 2,426 | 6.5% | 7.7% |
| 2036 | Ghent 4 | 1,831 | 2,267 | 5.8% | 7.2% |
| 2036 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Mill Creek 3 | 2,433 | 2,499 | 7.7% | 7.9% |
| 2036 | Mill Creek 4 | 2,782 | 2,996 | 8.8% | 9.5% |
| 2036 | Trimble County 1 | 2,532 | 2,522 | 8.0% | 8.0% |
| 2036 | Trimble County 2 | 2,819 | 3,199 | 8.9% | 10.2% |
| 2036 | Cane Run 7 2X1 | 5,206 | 4,887 | 16.5% | 15.5% |
| 2036 | Brown 5 | 23 | 50 | 0.1% | 0.2% |
| 2036 | Brown 6 | 70 | 93 | 0.2% | 0.3% |
| 2036 | Brown 7 | 48 | 76 | 0.2% | 0.2% |
| 2036 | Brown 8 | 11 | 0 | 0.0% | 0.0% |
| 2036 | Brown 9 | 10 | 0 | 0.0% | 0.0% |
| 2036 | Brown 10 | 6 | 0 | 0.0% | 0.0% |
| 2036 | Brown 11 | 4 | 0 | 0.0% | 0.0% |
| 2036 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 13 | 67 | 63 | 0.2% | 0.2% |
| 2036 | Trimble Co 05 | 298 | 397 | 0.9% | 1.3% |
| 2036 | Trimble Co 06 | 250 | 333 | 0.8% | 1.1% |
| 2036 | Trimble Co 07 | 199 | 276 | 0.6% | 0.9% |
| 2036 | Trimble Co 08 | 23 | 12 | 0.1% | 0.0% |
| 2036 | Trimble Co 09 | 148 | 219 | 0.5% | 0.7% |
| 2036 | Trimble Co 10 | 14 | 6 | 0.0% | 0.0% |
| 2036 | OVEC | 529 | 609 | 1.7% | 1.9% |
| 2036 | Brown Solar | 18 | 17 | 0.1% | 0.1% |
| 2036 | Dix Dam | 90 | 94 | 0.3% | 0.3% |
| 2036 | Ohio Falls | 301 | 278 | 1.0% | 0.9% |
| 2036 | Purchases | 13 | 0 | 0.0% | 0.0% |
| 2036 | Ragland Solar PPA | 0 | 365 | 0.0% | 1.2% |
| 2036 | Rhudes Creek Solar PPA | 0 | 210 | 0.0% | 0.7% |
| 2036 | New Battery Storage | 0 | 11 | 0.0% | 0.0% |
| 2036 | New NGCC 1 | 3,525 | 0 | 11.1% | 0.0% |
| 2036 | New NGCC 2 | 3,311 | 0 | 10.5% | 0.0% |
| 2036 | New NGCC 3 | 3,024 | 0 | 9.6% | 0.0% |
| 2036 | New SCCT 1 | 0 | 786 | 0.0% | 2.5% |
| 2036 | New SCCT 2 | 0 | 630 | 0.0% | 2.0% |
| 2036 | New SCCT 3 | 0 | 462 | 0.0% | 1.5% |
| 2036 | New SCCT 4 | 0 | 324 | 0.0% | 1.0% |
| 2036 | New SCCT 5 | 0 | 218 | 0.0% | 0.7% |
| 2036 | New SCCT 6 | 0 | 133 | 0.0% | 0.4% |
| 2036 | New Solar | 0 | 5,035 | 0.0% | 16.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2022 | Brown 3 | 1,008 | 1,247 | 3.5% | 4.3% |
| 2022 | Ghent 1 | 2,684 | 2,863 | 9.2% | 9.9% |
| 2022 | Ghent 2 | 2,902 | 2,842 | 10.0% | 9.8% |
| 2022 | Ghent 3 | 2,661 | 2,744 | 9.2% | 9.5% |
| 2022 | Ghent 4 | 2,377 | 2,433 | 8.2% | 8.4% |
| 2022 | Mill Creek 1 | 2,172 | 1,946 | 7.5% | 6.7% |
| 2022 | Mill Creek 2 | 866 | 857 | 3.0% | 3.0% |
| 2022 | Mill Creek 3 | 2,873 | 2,366 | 9.9% | 8.2% |
| 2022 | Mill Creek 4 | 2,877 | 2,747 | 9.9% | 9.5% |
| 2022 | Trimble County 1 | 2,740 | 2,554 | 9.4% | 8.8% |
| 2022 | Trimble County 2 | 2,799 | 3,242 | 9.6% | 11.2% |
| 2022 | Cane Run 7 2X1 | 2,084 | 1,945 | 7.2% | 6.7% |
| 2022 | Brown 5 | 50 | 34 | 0.2% | 0.1% |
| 2022 | Brown 6 | 66 | 40 | 0.2% | 0.1% |
| 2022 | Brown 7 | 43 | 34 | 0.1% | 0.1% |
| 2022 | Brown 8 | 5 | 8 | 0.0% | 0.0% |
| 2022 | Brown 9 | 9 | 19 | 0.0% | 0.1% |
| 2022 | Brown 10 | 9 | 16 | 0.0% | 0.1% |
| 2022 | Brown 11 | 5 | 8 | 0.0% | 0.0% |
| 2022 | Haefling | 0 | 1 | 0.0% | 0.0% |
| 2022 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2022 | Paddys Run 12 | 0 | 1 | 0.0% | 0.0% |
| 2022 | Paddys Run 13 | 40 | 70 | 0.1% | 0.2% |
| 2022 | Trimble Co 05 | 257 | 278 | 0.9% | 1.0% |
| 2022 | Trimble Co 06 | 199 | 232 | 0.7% | 0.8% |
| 2022 | Trimble Co 07 | 160 | 203 | 0.5% | 0.7% |
| 2022 | Trimble Co 08 | 29 | 63 | 0.1% | 0.2% |
| 2022 | Trimble Co 09 | 120 | 157 | 0.4% | 0.5% |
| 2022 | Trimble Co 10 | 15 | 44 | 0.1% | 0.2% |
| 2022 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2022 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2023 | Brown 3 | 1,200 | 1,235 | 4.1% | 4.2% |
| 2023 | Ghent 1 | 3,024 | 3,296 | 10.4% | 11.2% |
| 2023 | Ghent 2 | 3,042 | 3,080 | 10.5% | 10.5% |
| 2023 | Ghent 3 | 2,522 | 2,767 | 8.7% | 9.4% |
| 2023 | Ghent 4 | 2,462 | 2,683 | 8.5% | 9.1% |
| 2023 | Mill Creek 1 | 2,038 | 1,912 | 7.0% | 6.5% |
| 2023 | Mill Creek 2 | 857 | 883 | 2.9% | 3.0% |
| 2023 | Mill Creek 3 | 2,510 | 2,083 | 8.6% | 7.1% |
| 2023 | Mill Creek 4 | 3,264 | 3,125 | 11.2% | 10.7% |
| 2023 | Trimble County 1 | 2,597 | 2,548 | 8.9% | 8.7% |
| 2023 | Trimble County 2 | 2,570 | 2,846 | 8.8% | 9.7% |
| 2023 | Cane Run 7 2X1 | 2,123 | 1,897 | 7.3% | 6.5% |
| 2023 | Brown 5 | 130 | 47 | 0.4% | 0.2% |
| 2023 | Brown 6 | 61 | 60 | 0.2% | 0.2% |
| 2023 | Brown 7 | 41 | 45 | 0.1% | 0.2% |
| 2023 | Brown 8 | 11 | 8 | 0.0% | 0.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2023 | Brown 9 | 18 | 18 | 0.1% | 0.1% |
| 2023 | Brown 10 | 31 | 13 | 0.1% | 0.0% |
| 2023 | Brown 11 | 5 | 4 | 0.0% | 0.0% |
| 2023 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2023 | Paddys Run 13 | 26 | 28 | 0.1% | 0.1% |
| 2023 | Trimble Co 05 | 195 | 225 | 0.7% | 0.8% |
| 2023 | Trimble Co 06 | 136 | 182 | 0.5% | 0.6% |
| 2023 | Trimble Co 07 | 119 | 157 | 0.4% | 0.5% |
| 2023 | Trimble Co 08 | 22 | 45 | 0.1% | 0.2% |
| 2023 | Trimble Co 09 | 83 | 117 | 0.3% | 0.4% |
| 2023 | Trimble Co 10 | 10 | 27 | 0.0% | 0.1% |
| 2023 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2023 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2024 | Brown 3 | 1,173 | 1,359 | 4.0% | 4.6% |
| 2024 | Ghent 1 | 2,914 | 2,963 | 9.8% | 10.1% |
| 2024 | Ghent 2 | 2,670 | 2,527 | 9.0% | 8.6% |
| 2024 | Ghent 3 | 2,524 | 2,625 | 8.5% | 8.9% |
| 2024 | Ghent 4 | 2,337 | 2,139 | 7.9% | 7.3% |
| 2024 | Mill Creek 1 | 2,321 | 2,266 | 7.8% | 7.7% |
| 2024 | Mill Creek 2 | 896 | 1,008 | 3.0% | 3.4% |
| 2024 | Mill Creek 3 | 3,035 | 2,736 | 10.3% | 9.3% |
| 2024 | Mill Creek 4 | 3,284 | 3,300 | 11.1% | 11.2% |
| 2024 | Trimble County 1 | 2,775 | 2,656 | 9.4% | 9.0% |
| 2024 | Trimble County 2 | 2,924 | 3,050 | 9.9% | 10.4% |
| 2024 | Cane Run 7 2X1 | 1,829 | 1,835 | 6.2% | 6.2% |
| 2024 | Brown 5 | 111 | 60 | 0.4% | 0.2% |
| 2024 | Brown 6 | 55 | 66 | 0.2% | 0.2% |
| 2024 | Brown 7 | 40 | 46 | 0.1% | 0.2% |
| 2024 | Brown 8 | 10 | 5 | 0.0% | 0.0% |
| 2024 | Brown 9 | 19 | 9 | 0.1% | 0.0% |
| 2024 | Brown 10 | 28 | 8 | 0.1% | 0.0% |
| 2024 | Brown 11 | 6 | 3 | 0.0% | 0.0% |
| 2024 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2024 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2024 | Paddys Run 12 | 0 | 1 | 0.0% | 0.0% |
| 2024 | Paddys Run 13 | 29 | 25 | 0.1% | 0.1% |
| 2024 | Trimble Co 05 | 225 | 241 | 0.8% | 0.8% |
| 2024 | Trimble Co 06 | 168 | 190 | 0.6% | 0.6% |
| 2024 | Trimble Co 07 | 109 | 115 | 0.4% | 0.4% |
| 2024 | Trimble Co 08 | 22 | 40 | 0.1% | 0.1% |
| 2024 | Trimble Co 09 | 83 | 102 | 0.3% | 0.3% |
| 2024 | Trimble Co 10 | 14 | 21 | 0.0% | 0.1% |
| 2024 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2024 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2024 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Brown 3 | 1,006 | 1,158 | 3.5% | 4.1% |
| 2025 | Ghent 1 | 2,707 | 2,734 | 9.4% | 9.7% |
| 2025 | Ghent 2 | 2,930 | 2,880 | 10.2% | 10.2% |
| 2025 | Ghent 3 | 2,466 | 2,568 | 8.5% | 9.1% |
| 2025 | Ghent 4 | 2,463 | 2,166 | 8.5% | 7.7% |
| 2025 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Mill Creek 2 | 2,276 | 2,208 | 7.9% | 7.8% |
| 2025 | Mill Creek 3 | 2,796 | 2,560 | 9.7% | 9.1% |
| 2025 | Mill Creek 4 | 3,621 | 3,632 | 12.6% | 12.8% |
| 2025 | Trimble County 1 | 2,446 | 2,325 | 8.5% | 8.2% |
| 2025 | Trimble County 2 | 2,915 | 3,014 | 10.1% | 10.7% |
| 2025 | Cane Run 7 2X1 | 2,133 | 2,077 | 7.4% | 7.3% |
| 2025 | Brown 5 | 135 | 81 | 0.5% | 0.3% |
| 2025 | Brown 6 | 59 | 67 | 0.2% | 0.2% |
| 2025 | Brown 7 | 37 | 55 | 0.1% | 0.2% |
| 2025 | Brown 8 | 7 | 6 | 0.0% | 0.0% |
| 2025 | Brown 9 | 18 | 9 | 0.1% | 0.0% |
| 2025 | Brown 10 | 33 | 9 | 0.1% | 0.0% |
| 2025 | Brown 11 | 3 | 3 | 0.0% | 0.0% |
| 2025 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2025 | Paddys Run 13 | 23 | 24 | 0.1% | 0.1% |
| 2025 | Trimble Co 05 | 289 | 232 | 1.0% | 0.8% |
| 2025 | Trimble Co 06 | 211 | 182 | 0.7% | 0.6% |
| 2025 | Trimble Co 07 | 152 | 140 | 0.5% | 0.5% |
| 2025 | Trimble Co 08 | 20 | 34 | 0.1% | 0.1% |
| 2025 | Trimble Co 09 | 88 | 84 | 0.3% | 0.3% |
| 2025 | Trimble Co 10 | 9 | 20 | 0.0% | 0.1% |
| 2025 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2025 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Brown 3 | 948 | 1,132 | 3.3% | 4.0% |
| 2026 | Ghent 1 | 2,904 | 3,007 | 10.1% | 10.6% |
| 2026 | Ghent 2 | 2,892 | 2,786 | 10.1% | 9.9% |
| 2026 | Ghent 3 | 2,354 | 2,383 | 8.2% | 8.4% |
| 2026 | Ghent 4 | 2,354 | 2,100 | 8.2% | 7.4% |
| 2026 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Mill Creek 2 | 2,015 | 2,145 | 7.0% | 7.6% |
| 2026 | Mill Creek 3 | 3,047 | 2,782 | 10.6% | 9.8% |
| 2026 | Mill Creek 4 | 3,346 | 3,614 | 11.6% | 12.8% |
| 2026 | Trimble County 1 | 2,786 | 2,609 | 9.7% | 9.2% |
| 2026 | Trimble County 2 | 2,611 | 2,766 | 9.1% | 9.8% |
| 2026 | Cane Run 7 2X1 | 2,086 | 2,053 | 7.3% | 7.3% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2026 | Brown 5 | 161 | 78 | 0.6% | 0.3% |
| 2026 | Brown 6 | 78 | 81 | 0.3% | 0.3% |
| 2026 | Brown 7 | 63 | 60 | 0.2% | 0.2% |
| 2026 | Brown 8 | 11 | 10 | 0.0% | 0.0% |
| 2026 | Brown 9 | 32 | 18 | 0.1% | 0.1% |
| 2026 | Brown 10 | 20 | 17 | 0.1% | 0.1% |
| 2026 | Brown 11 | 7 | 7 | 0.0% | 0.0% |
| 2026 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2026 | Paddys Run 13 | 30 | 14 | 0.1% | 0.0% |
| 2026 | Trimble Co 05 | 320 | 193 | 1.1% | 0.7% |
| 2026 | Trimble Co 06 | 258 | 137 | 0.9% | 0.5% |
| 2026 | Trimble Co 07 | 196 | 118 | 0.7% | 0.4% |
| 2026 | Trimble Co 08 | 31 | 34 | 0.1% | 0.1% |
| 2026 | Trimble Co 09 | 161 | 79 | 0.6% | 0.3% |
| 2026 | Trimble Co 10 | 19 | 18 | 0.1% | 0.1% |
| 2026 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2026 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Brown 3 | 854 | 1,177 | 3.0% | 4.2% |
| 2027 | Ghent 1 | 2,894 | 2,933 | 10.1% | 10.5% |
| 2027 | Ghent 2 | 2,563 | 2,518 | 8.9% | 9.0% |
| 2027 | Ghent 3 | 2,552 | 2,522 | 8.9% | 9.0% |
| 2027 | Ghent 4 | 2,361 | 2,201 | 8.2% | 7.9% |
| 2027 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Mill Creek 2 | 2,283 | 2,254 | 8.0% | 8.1% |
| 2027 | Mill Creek 3 | 2,614 | 2,358 | 9.1% | 8.4% |
| 2027 | Mill Creek 4 | 3,587 | 3,256 | 12.5% | 11.7% |
| 2027 | Trimble County 1 | 2,682 | 2,562 | 9.4% | 9.2% |
| 2027 | Trimble County 2 | 2,913 | 3,122 | 10.2% | 11.2% |
| 2027 | Cane Run 7 2X1 | 2,134 | 2,115 | 7.4% | 7.6% |
| 2027 | Brown 5 | 134 | 83 | 0.5% | 0.3% |
| 2027 | Brown 6 | 80 | 59 | 0.3% | 0.2% |
| 2027 | Brown 7 | 66 | 43 | 0.2% | 0.2% |
| 2027 | Brown 8 | 13 | 17 | 0.0% | 0.1% |
| 2027 | Brown 9 | 31 | 11 | 0.1% | 0.0% |
| 2027 | Brown 10 | 21 | 21 | 0.1% | 0.1% |
| 2027 | Brown 11 | 10 | 10 | 0.0% | 0.0% |
| 2027 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2027 | Paddys Run 13 | 53 | 12 | 0.2% | 0.0% |
| 2027 | Trimble Co 05 | 279 | 219 | 1.0% | 0.8% |
| 2027 | Trimble Co 06 | 154 | 172 | 0.5% | 0.6% |
| 2027 | Trimble Co 07 | 196 | 132 | 0.7% | 0.5% |
| 2027 | Trimble Co 08 | 37 | 33 | 0.1% | 0.1% |
| 2027 | Trimble Co 09 | 118 | 91 | 0.4% | 0.3% |
| 2027 | Trimble Co 10 | 19 | 21 | 0.1% | 0.1% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2027 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 1 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 2 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2027 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Brown 3 | 903 | 0 | 3.1% | 0.0% |
| 2028 | Ghent 1 | 2,891 | 3,058 | 9.9% | 11.5% |
| 2028 | Ghent 2 | 2,928 | 2,913 | 10.1% | 11.0% |
| 2028 | Ghent 3 | 2,675 | 2,754 | 9.2% | 10.4% |
| 2028 | Ghent 4 | 2,170 | 2,187 | 7.5% | 8.2% |
| 2028 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Mill Creek 2 | 2,187 | 0 | 7.5% | 0.0% |
| 2028 | Mill Creek 3 | 3,066 | 2,861 | 10.5% | 10.8% |
| 2028 | Mill Creek 4 | 3,268 | 3,312 | 11.2% | 12.5% |
| 2028 | Trimble County 1 | 2,836 | 2,718 | 9.8% | 10.2% |
| 2028 | Trimble County 2 | 2,976 | 3,231 | 10.2% | 12.2% |
| 2028 | Cane Run 7 2X1 | 1,833 | 1,800 | 6.3% | 6.8% |
| 2028 | Brown 5 | 115 | 173 | 0.4% | 0.7% |
| 2028 | Brown 6 | 78 | 66 | 0.3% | 0.2% |
| 2028 | Brown 7 | 65 | 51 | 0.2% | 0.2% |
| 2028 | Brown 8 | 25 | 49 | 0.1% | 0.2% |
| 2028 | Brown 9 | 20 | 63 | 0.1% | 0.2% |
| 2028 | Brown 10 | 14 | 34 | 0.0% | 0.1% |
| 2028 | Brown 11 | 8 | 24 | 0.0% | 0.1% |
| 2028 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2028 | Paddys Run 13 | 65 | 36 | 0.2% | 0.1% |
| 2028 | Trimble Co 05 | 259 | 245 | 0.9% | 0.9% |
| 2028 | Trimble Co 06 | 266 | 180 | 0.9% | 0.7% |
| 2028 | Trimble Co 07 | 228 | 158 | 0.8% | 0.6% |
| 2028 | Trimble Co 08 | 26 | 16 | 0.1% | 0.1% |
| 2028 | Trimble Co 09 | 168 | 116 | 0.6% | 0.4% |
| 2028 | Trimble Co 10 | 13 | 5 | 0.0% | 0.0% |
| 2028 | New NGCC 1 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 1 | 0 | 302 | 0.0% | 1.1% |
| 2028 | New SCCT 2 | 0 | 207 | 0.0% | 0.8% |
| 2028 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2028 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Brown 3 | 751 | 0 | 2.7% | 0.0% |
| 2029 | Ghent 1 | 2,549 | 2,695 | 9.1% | 10.3% |
| 2029 | Ghent 2 | 2,798 | 2,875 | 10.0% | 11.0% |
| 2029 | Ghent 3 | 2,597 | 2,729 | 9.3% | 10.5% |
| 2029 | Ghent 4 | 2,339 | 2,249 | 8.3% | 8.6% |
| 2029 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Mill Creek 2 | 1,631 | 0 | 5.8% | 0.0% |
| 2029 | Mill Creek 3 | 2,805 | 2,597 | 10.0% | 10.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2029 | Mill Creek 4 | 3,557 | 3,672 | 12.7% | 14.1% |
| 2029 | Trimble County 1 | 2,687 | 2,566 | 9.6% | 9.8% |
| 2029 | Trimble County 2 | 2,915 | 3,164 | 10.4% | 12.1% |
| 2029 | Cane Run 7 2X1 | 2,120 | 2,109 | 7.6% | 8.1% |
| 2029 | Brown 5 | 53 | 147 | 0.2% | 0.6% |
| 2029 | Brown 6 | 46 | 48 | 0.2% | 0.2% |
| 2029 | Brown 7 | 32 | 36 | 0.1% | 0.1% |
| 2029 | Brown 8 | 5 | 38 | 0.0% | 0.1% |
| 2029 | Brown 9 | 7 | 63 | 0.0% | 0.2% |
| 2029 | Brown 10 | 5 | 33 | 0.0% | 0.1% |
| 2029 | Brown 11 | 3 | 14 | 0.0% | 0.1% |
| 2029 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2029 | Paddys Run 13 | 39 | 31 | 0.1% | 0.1% |
| 2029 | Trimble Co 05 | 263 | 174 | 0.9% | 0.7% |
| 2029 | Trimble Co 06 | 209 | 62 | 0.7% | 0.2% |
| 2029 | Trimble Co 07 | 164 | 125 | 0.6% | 0.5% |
| 2029 | Trimble Co 08 | 13 | 10 | 0.0% | 0.0% |
| 2029 | Trimble Co 09 | 120 | 76 | 0.4% | 0.3% |
| 2029 | Trimble Co 10 | 6 | 5 | 0.0% | 0.0% |
| 2029 | New NGCC 1 | 351 | 0 | 1.3% | 0.0% |
| 2029 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 1 | 0 | 323 | 0.0% | 1.2% |
| 2029 | New SCCT 2 | 0 | 224 | 0.0% | 0.9% |
| 2029 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2029 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Ghent 1 | 2,776 | 2,952 | 10.6% | 11.4% |
| 2030 | Ghent 2 | 2,652 | 2,698 | 10.1% | 10.4% |
| 2030 | Ghent 3 | 2,365 | 2,528 | 9.0% | 9.7% |
| 2030 | Ghent 4 | 2,285 | 2,342 | 8.7% | 9.0% |
| 2030 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Mill Creek 3 | 3,017 | 2,892 | 11.5% | 11.1% |
| 2030 | Mill Creek 4 | 3,068 | 3,119 | 11.7% | 12.0% |
| 2030 | Trimble County 1 | 2,770 | 2,679 | 10.6% | 10.3% |
| 2030 | Trimble County 2 | 2,868 | 3,126 | 10.9% | 12.0% |
| 2030 | Cane Run 7 2X1 | 2,078 | 2,081 | 7.9% | 8.0% |
| 2030 | Brown 5 | 46 | 142 | 0.2% | 0.5% |
| 2030 | Brown 6 | 60 | 40 | 0.2% | 0.2% |
| 2030 | Brown 7 | 40 | 32 | 0.2% | 0.1% |
| 2030 | Brown 8 | 9 | 37 | 0.0% | 0.1% |
| 2030 | Brown 9 | 12 | 49 | 0.0% | 0.2% |
| 2030 | Brown 10 | 9 | 36 | 0.0% | 0.1% |
| 2030 | Brown 11 | 4 | 10 | 0.0% | 0.0% |
| 2030 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2030 | Paddys Run 13 | 54 | 27 | 0.2% | 0.1% |
| 2030 | Trimble Co 05 | 285 | 201 | 1.1% | 0.8% |
| 2030 | Trimble Co 06 | 234 | 176 | 0.9% | 0.7% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2030 | Trimble Co 07 | 181 | 139 | 0.7% | 0.5% |
| 2030 | Trimble Co 08 | 22 | 16 | 0.1% | 0.1% |
| 2030 | Trimble Co 09 | 127 | 91 | 0.5% | 0.4% |
| 2030 | Trimble Co 10 | 10 | 9 | 0.0% | 0.0% |
| 2030 | New NGCC 1 | 1,242 | 0 | 4.7% | 0.0% |
| 2030 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 1 | 0 | 306 | 0.0% | 1.2% |
| 2030 | New SCCT 2 | 0 | 227 | 0.0% | 0.9% |
| 2030 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2030 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Ghent 1 | 2,843 | 3,037 | 10.8% | 11.7% |
| 2031 | Ghent 2 | 2,807 | 2,823 | 10.6% | 10.8% |
| 2031 | Ghent 3 | 2,500 | 2,644 | 9.5% | 10.2% |
| 2031 | Ghent 4 | 2,290 | 2,289 | 8.7% | 8.8% |
| 2031 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Mill Creek 3 | 2,843 | 2,676 | 10.8% | 10.3% |
| 2031 | Mill Creek 4 | 3,501 | 3,642 | 13.3% | 14.0% |
| 2031 | Trimble County 1 | 2,573 | 2,482 | 9.7% | 9.5% |
| 2031 | Trimble County 2 | 2,883 | 3,105 | 10.9% | 11.9% |
| 2031 | Cane Run 7 2X1 | 2,057 | 2,073 | 7.8% | 8.0% |
| 2031 | Brown 5 | 31 | 79 | 0.1% | 0.3% |
| 2031 | Brown 6 | 52 | 53 | 0.2% | 0.2% |
| 2031 | Brown 7 | 41 | 35 | 0.2% | 0.1% |
| 2031 | Brown 8 | 9 | 9 | 0.0% | 0.0% |
| 2031 | Brown 9 | 20 | 15 | 0.1% | 0.1% |
| 2031 | Brown 10 | 12 | 10 | 0.0% | 0.0% |
| 2031 | Brown 11 | 4 | 5 | 0.0% | 0.0% |
| 2031 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2031 | Paddys Run 13 | 47 | 26 | 0.2% | 0.1% |
| 2031 | Trimble Co 05 | 224 | 182 | 0.8% | 0.7% |
| 2031 | Trimble Co 06 | 183 | 146 | 0.7% | 0.6% |
| 2031 | Trimble Co 07 | 149 | 112 | 0.6% | 0.4% |
| 2031 | Trimble Co 08 | 18 | 12 | 0.1% | 0.0% |
| 2031 | Trimble Co 09 | 107 | 83 | 0.4% | 0.3% |
| 2031 | Trimble Co 10 | 11 | 7 | 0.0% | 0.0% |
| 2031 | New NGCC 1 | 1,211 | 0 | 4.6% | 0.0% |
| 2031 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 1 | 0 | 302 | 0.0% | 1.2% |
| 2031 | New SCCT 2 | 0 | 200 | 0.0% | 0.8% |
| 2031 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2031 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Ghent 1 | 2,846 | 2,969 | 10.7% | 11.3% |
| 2032 | Ghent 2 | 2,870 | 2,908 | 10.8% | 11.1% |
| 2032 | Ghent 3 | 2,463 | 2,687 | 9.3% | 10.2% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2032 | Ghent 4 | 2,264 | 2,343 | 8.5% | 8.9% |
| 2032 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Mill Creek 3 | 3,040 | 2,872 | 11.5% | 10.9% |
| 2032 | Mill Creek 4 | 3,335 | 3,440 | 12.6% | 13.1% |
| 2032 | Trimble County 1 | 2,747 | 2,679 | 10.4% | 10.2% |
| 2032 | Trimble County 2 | 2,887 | 3,133 | 10.9% | 11.9% |
| 2032 | Cane Run 7 2X1 | 1,932 | 1,925 | 7.3% | 7.3% |
| 2032 | Brown 5 | 28 | 82 | 0.1% | 0.3% |
| 2032 | Brown 6 | 53 | 50 | 0.2% | 0.2% |
| 2032 | Brown 7 | 37 | 36 | 0.1% | 0.1% |
| 2032 | Brown 8 | 9 | 8 | 0.0% | 0.0% |
| 2032 | Brown 9 | 13 | 12 | 0.0% | 0.0% |
| 2032 | Brown 10 | 9 | 8 | 0.0% | 0.0% |
| 2032 | Brown 11 | 3 | 3 | 0.0% | 0.0% |
| 2032 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2032 | Paddys Run 13 | 53 | 32 | 0.2% | 0.1% |
| 2032 | Trimble Co 05 | 231 | 219 | 0.9% | 0.8% |
| 2032 | Trimble Co 06 | 184 | 177 | 0.7% | 0.7% |
| 2032 | Trimble Co 07 | 139 | 146 | 0.5% | 0.6% |
| 2032 | Trimble Co 08 | 20 | 17 | 0.1% | 0.1% |
| 2032 | Trimble Co 09 | 105 | 98 | 0.4% | 0.4% |
| 2032 | Trimble Co 10 | 12 | 8 | 0.0% | 0.0% |
| 2032 | New NGCC 1 | 1,246 | 0 | 4.7% | 0.0% |
| 2032 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 1 | 0 | 266 | 0.0% | 1.0% |
| 2032 | New SCCT 2 | 0 | 184 | 0.0% | 0.7% |
| 2032 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2032 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Ghent 1 | 2,871 | 3,059 | 10.9% | 11.7% |
| 2033 | Ghent 2 | 2,799 | 2,845 | 10.6% | 10.9% |
| 2033 | Ghent 3 | 2,525 | 2,702 | 9.6% | 10.4% |
| 2033 | Ghent 4 | 2,355 | 2,351 | 8.9% | 9.0% |
| 2033 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Mill Creek 3 | 2,817 | 2,678 | 10.7% | 10.3% |
| 2033 | Mill Creek 4 | 3,522 | 3,620 | 13.4% | 13.9% |
| 2033 | Trimble County 1 | 2,387 | 2,283 | 9.0% | 8.8% |
| 2033 | Trimble County 2 | 2,888 | 3,087 | 10.9% | 11.9% |
| 2033 | Cane Run 7 2X1 | 2,012 | 2,011 | 7.6% | 7.7% |
| 2033 | Brown 5 | 24 | 101 | 0.1% | 0.4% |
| 2033 | Brown 6 | 65 | 24 | 0.2% | 0.1% |
| 2033 | Brown 7 | 45 | 19 | 0.2% | 0.1% |
| 2033 | Brown 8 | 7 | 8 | 0.0% | 0.0% |
| 2033 | Brown 9 | 12 | 14 | 0.0% | 0.1% |
| 2033 | Brown 10 | 11 | 9 | 0.0% | 0.0% |
| 2033 | Brown 11 | 6 | 2 | 0.0% | 0.0% |
| 2033 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2033 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2033 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2033 | Paddys Run 13 | 58 | 36 | 0.2% | 0.1% |
| 2033 | Trimble Co 05 | 245 | 234 | 0.9% | 0.9% |
| 2033 | Trimble Co 06 | 207 | 203 | 0.8% | 0.8% |
| 2033 | Trimble Co 07 | 159 | 143 | 0.6% | 0.5% |
| 2033 | Trimble Co 08 | 26 | 17 | 0.1% | 0.1% |
| 2033 | Trimble Co 09 | 118 | 103 | 0.4% | 0.4% |
| 2033 | Trimble Co 10 | 14 | 8 | 0.1% | 0.0% |
| 2033 | New NGCC 1 | 1,207 | 0 | 4.6% | 0.0% |
| 2033 | New NGCC 2 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New NGCC 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 1 | 0 | 282 | 0.0% | 1.1% |
| 2033 | New SCCT 2 | 0 | 201 | 0.0% | 0.8% |
| 2033 | New SCCT 3 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 4 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 5 | 0 | 0 | 0.0% | 0.0% |
| 2033 | New SCCT 6 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Ghent 1 | 849 | 0 | 3.6% | 0.0% |
| 2034 | Ghent 2 | 1,023 | 0 | 4.4% | 0.0% |
| 2034 | Ghent 3 | 2,424 | 2,672 | 10.3% | 12.6% |
| 2034 | Ghent 4 | 2,214 | 2,461 | 9.4% | 11.6% |
| 2034 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Mill Creek 3 | 2,774 | 2,679 | 11.8% | 12.6% |
| 2034 | Mill Creek 4 | 3,099 | 3,179 | 13.2% | 15.0% |
| 2034 | Trimble County 1 | 2,711 | 2,669 | 11.6% | 12.6% |
| 2034 | Trimble County 2 | 2,507 | 2,810 | 10.7% | 13.2% |
| 2034 | Cane Run 7 2X1 | 2,089 | 1,983 | 8.9% | 9.3% |
| 2034 | Brown 5 | 14 | 53 | 0.1% | 0.3% |
| 2034 | Brown 6 | 48 | 79 | 0.2% | 0.4% |
| 2034 | Brown 7 | 35 | 64 | 0.1% | 0.3% |
| 2034 | Brown 8 | 8 | 1 | 0.0% | 0.0% |
| 2034 | Brown 9 | 7 | 0 | 0.0% | 0.0% |
| 2034 | Brown 10 | 5 | 44 | 0.0% | 0.2% |
| 2034 | Brown 11 | 3 | 1 | 0.0% | 0.0% |
| 2034 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2034 | Paddys Run 13 | 50 | 36 | 0.2% | 0.2% |
| 2034 | Trimble Co 05 | 216 | 265 | 0.9% | 1.2% |
| 2034 | Trimble Co 06 | 170 | 236 | 0.7% | 1.1% |
| 2034 | Trimble Co 07 | 128 | 202 | 0.5% | 1.0% |
| 2034 | Trimble Co 08 | 16 | 5 | 0.1% | 0.0% |
| 2034 | Trimble Co 09 | 100 | 159 | 0.4% | 0.7% |
| 2034 | Trimble Co 10 | 10 | 4 | 0.0% | 0.0% |
| 2034 | New NGCC 1 | 1,265 | 0 | 5.4% | 0.0% |
| 2034 | New NGCC 2 | 862 | 0 | 3.7% | 0.0% |
| 2034 | New NGCC 3 | 813 | 0 | 3.5% | 0.0% |
| 2034 | New SCCT 1 | 0 | 509 | 0.0% | 2.4% |
| 2034 | New SCCT 2 | 0 | 411 | 0.0% | 1.9% |
| 2034 | New SCCT 3 | 0 | 300 | 0.0% | 1.4% |
| 2034 | New SCCT 4 | 0 | 212 | 0.0% | 1.0% |
| 2034 | New SCCT 5 | 0 | 138 | 0.0% | 0.6% |
| 2034 | New SCCT 6 | 0 | 76 | 0.0% | 0.4% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2035 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 1 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 2 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Ghent 3 | 2,374 | 2,675 | 10.8% | 12.5% |
| 2035 | Ghent 4 | 2,095 | 2,509 | 9.5% | 11.7% |
| 2035 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Mill Creek 3 | 2,388 | 2,395 | 10.8% | 11.2% |
| 2035 | Mill Creek 4 | 3,185 | 3,474 | 14.5% | 16.2% |
| 2035 | Trimble County 1 | 2,487 | 2,533 | 11.3% | 11.8% |
| 2035 | Trimble County 2 | 2,748 | 3,114 | 12.5% | 14.5% |
| 2035 | Cane Run 7 2X1 | 1,786 | 1,725 | 8.1% | 8.0% |
| 2035 | Brown 5 | 26 | 62 | 0.1% | 0.3% |
| 2035 | Brown 6 | 63 | 72 | 0.3% | 0.3% |
| 2035 | Brown 7 | 51 | 52 | 0.2% | 0.2% |
| 2035 | Brown 8 | 18 | 0 | 0.1% | 0.0% |
| 2035 | Brown 9 | 10 | 0 | 0.0% | 0.0% |
| 2035 | Brown 10 | 8 | 0 | 0.0% | 0.0% |
| 2035 | Brown 11 | 7 | 1 | 0.0% | 0.0% |
| 2035 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2035 | Paddys Run 13 | 61 | 41 | 0.3% | 0.2% |
| 2035 | Trimble Co 05 | 250 | 313 | 1.1% | 1.5% |
| 2035 | Trimble Co 06 | 204 | 274 | 0.9% | 1.3% |
| 2035 | Trimble Co 07 | 162 | 236 | 0.7% | 1.1% |
| 2035 | Trimble Co 08 | 26 | 9 | 0.1% | 0.0% |
| 2035 | Trimble Co 09 | 134 | 190 | 0.6% | 0.9% |
| 2035 | Trimble Co 10 | 18 | 5 | 0.1% | 0.0% |
| 2035 | New NGCC 1 | 1,352 | 0 | 6.1% | 0.0% |
| 2035 | New NGCC 2 | 1,316 | 0 | 6.0% | 0.0% |
| 2035 | New NGCC 3 | 1,243 | 0 | 5.6% | 0.0% |
| 2035 | New SCCT 1 | 0 | 530 | 0.0% | 2.5% |
| 2035 | New SCCT 2 | 0 | 417 | 0.0% | 1.9% |
| 2035 | New SCCT 3 | 0 | 316 | 0.0% | 1.5% |
| 2035 | New SCCT 4 | 0 | 234 | 0.0% | 1.1% |
| 2035 | New SCCT 5 | 0 | 165 | 0.0% | 0.8% |
| 2035 | New SCCT 6 | 0 | 92 | 0.0% | 0.4% |
| 2036 | Brown 3 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Ghent 1 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Ghent 2 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Ghent 3 | 2,256 | 2,639 | 10.2% | 12.3% |
| 2036 | Ghent 4 | 2,051 | 2,518 | 9.3% | 11.7% |
| 2036 | Mill Creek 1 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Mill Creek 2 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Mill Creek 3 | 2,686 | 2,738 | 12.2% | 12.8% |
| 2036 | Mill Creek 4 | 2,997 | 3,211 | 13.6% | 15.0% |
| 2036 | Trimble County 1 | 2,681 | 2,670 | 12.2% | 12.4% |
| 2036 | Trimble County 2 | 2,726 | 3,063 | 12.4% | 14.3% |
| 2036 | Cane Run 7 2X1 | 2,059 | 1,954 | 9.3% | 9.1% |
| 2036 | Brown 5 | 21 | 48 | 0.1% | 0.2% |
| 2036 | Brown 6 | 49 | 64 | 0.2% | 0.3% |
| 2036 | Brown 7 | 34 | 52 | 0.2% | 0.2% |
| 2036 | Brown 8 | 10 | 0 | 0.0% | 0.0% |
| 2036 | Brown 9 | 10 | 0 | 0.0% | 0.0% |

| Year | Unit | CO2 Emissions (000s tons) | | Percentage Contribution To Annual Total | |
|---|---|---|---|---|---|
| | | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel | Case Nos 2020-00349 and 00350 | 2021 IRP Base Load, Base Fuel |
| 2036 | Brown 10 | 6 | 0 | 0.0% | 0.0% |
| 2036 | Brown 11 | 4 | 0 | 0.0% | 0.0% |
| 2036 | Haefling | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 11 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 12 | 0 | 0 | 0.0% | 0.0% |
| 2036 | Paddys Run 13 | 46 | 44 | 0.2% | 0.2% |
| 2036 | Trimble Co 05 | 204 | 273 | 0.9% | 1.3% |
| 2036 | Trimble Co 06 | 171 | 229 | 0.8% | 1.1% |
| 2036 | Trimble Co 07 | 135 | 190 | 0.6% | 0.9% |
| 2036 | Trimble Co 08 | 15 | 8 | 0.1% | 0.0% |
| 2036 | Trimble Co 09 | 100 | 150 | 0.5% | 0.7% |
| 2036 | Trimble Co 10 | 10 | 4 | 0.0% | 0.0% |
| 2036 | New NGCC 1 | 1,347 | 0 | 6.1% | 0.0% |
| 2036 | New NGCC 2 | 1,267 | 0 | 5.7% | 0.0% |
| 2036 | New NGCC 3 | 1,160 | 0 | 5.3% | 0.0% |
| 2036 | New SCCT 1 | 0 | 493 | 0.0% | 2.3% |
| 2036 | New SCCT 2 | 0 | 394 | 0.0% | 1.8% |
| 2036 | New SCCT 3 | 0 | 289 | 0.0% | 1.3% |
| 2036 | New SCCT 4 | 0 | 202 | 0.0% | 0.9% |
| 2036 | New SCCT 5 | 0 | 136 | 0.0% | 0.6% |
| 2036 | New SCCT 6 | 0 | 83 | 0.0% | 0.4% |

**LOUISVILLE GAS AND ELECTRIC COMPANY**
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**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.17**

**Responding Witness: Stuart A. Wilson**

Q-2.17. Refer to the figures in Table 12 of the Analysis of Generating Unit Retirement Years produced in the Companies' response to JI Q1- 19(c). Please provide all supporting analyses, workpapers, and documentation (in machine-readable format with formulas intact) for these figures.

A-2.17. See attachment being provided in Excel format. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. Heat rates, summer net capacity, and winter net capacity used values from the Companies' combustion turbines at Trimble County. Firm transmission costs were not applicable because replacement generation was assumed to be in the Companies' service territory.

The attachment is being provided in a separate file in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
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**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.18**

**Responding Witness: Stuart A. Wilson**

Q-2.18. Refer to page 1 of the attachment to Companies' response to JI Q1- 24, stating that the depreciation review process consisted of "evaluating key parameters . . . with equipment condition . . . to provide a risk-based assessment regarding the likelihood of equipment failure as compared to industry norms." Please provide the described evaluation and analysis, as well as all supporting workpapers and documentation.

A-2.18. The February 2022 review by Generation Engineering addressed the methodology and assumptions of the initial 2018 study to the extent that significant issues with boiler drums, turbines, and generators would be considerations for unit retirement. For documentation supporting the 2018 analysis, see attached.

EPRI states that a critical flaw size crack appear on average around 30 year of service (240,000 hours).

EPRI states that the average number of cycles of a coal drum unit has been 1,700 normal starts/stops to drive a critical flaw to failure.

EPRI states that Natural Circulation boilers are more susceptible to ligament cracking than are Forced Circulation boilers.

| Unit | Hours | Starts | Circulation | Years Until Undetected Typically Cracks Appear | Number of Starts to Reach 1,700 | Average Hours / Starts | Remaining Years Based on Starts and Hours | Average End of Drum Life | Depreciation Study |
|---|---|---|---|---|---|---|---|---|---|
| BR1 | 392,634 | 999 | Natural | Likely Present | 701 | 393 | 34 | 2052 | 2028 |
| BR2 | 365,569 | 811 | Natural | Likely Present | 889 | 451 | 50 | 2068 | 2034 |
| BR3 | 305,989 | 729 | Forced | Likely Present | 971 | 420 | 51 | 2069 | 2035 |
| GH1 | 306,100 | 448 | Forced | Likely Present | 1,252 | 683 | 107 | 2125 | 2034 |
| GH2 | 279,388 | 399 | Forced | Likely Present | 1,301 | 700 | 114 | 2132 | 2034 |
| GH3 | 243,166 | 425 | Natural | Likely Present | 1,275 | 572 | 91 | 2109 | 2037 |
| GH4 | 233,743 | 358 | Natural | 1 | 1,342 | 653 | 110 | 2128 | 2038 |
| MC1 | 312,956 | 1,129 | Forced | Likely Present | 571 | 277 | 20 | 2038 | 2034 |
| MC2 | 298,382 | 996 | Forced | Likely Present | 704 | 300 | 26 | 2044 | 2034 |
| MC3 | 263,673 | 1,143 | Natural | Likely Present | 557 | 231 | 16 | 2034 | 2038 |
| MC4 | 232,579 | 1,136 | Natural | 1 | 564 | 205 | 14 | 2032 | 2042 |
| TC1 | 193,779 | 636 | Forced | 6 | 1,064 | 305 | 41 | 2059 | 2050 |
| TC2 | 29,576 | 126 | Forced | 27 | 1,574 | 235 | 46 | 2064 | 2066 |

Based on EPRI's research and my review of our units to their data, the boiler drum should not reduce the retirement year of each unit. Note: While the Average End of Drum Life for MC3, MC4 & TC1 are just short of the year in the Depreciation Study, the difference is not signficant when considering these are typical and average numbers basis of analysis.

Date: 5/22/18

| Station | Unit | Current Retirement | Expected Life (yr) | Generator Condition Adjustment (yr) | Adjusted Generator only expected life (yr) | Justification |
|---|---|---|---|---|---|---|
| MC | 1 | 2032 | 60 | 13 | 73 | armature winding replaced in 2015, design life is 30 years<br>core iron inspected and reparied in 2015, expected life +30 years |
| MC | 2 | 2034 | 60 | 13 | 73 | armature winding replaced in 2015, design life is 30 years<br>core iron inspected and reparied in 2015, expected life +30 years |
| MC | 3 | 2038 | 60 | 11 | 71 | armature winding to be replaced in 2019, design life is 30 years<br>core iron to be inspected and reparied in 2019, expected life +30 years<br>* assumes work scheduled for 2019 is completed in 2019 |
| MC | 4 | 2042 | 60 | 2 | 62 | armature winding replaced in 2014, design life is 30 years<br>core iron inspected and reparied in 2014, expected life +30 years |
| TC | 1 | 2050 | 60 | 0 | 60 | generator is regularly inspected, no know issues<br>armature rewind kit is availble |
| TC | 2 | 2066 | 55 | -3 | 52 | generator is regularly inspected, no know issues<br>generator field rewound in,  other minor repairs to stator in 2016<br>current OEM support is poor |
| BR | 1 | 2028 | 72 | -10 | 62 | armature winding is 59 years old, design life is 30 years<br>generator is regularly inspected, shorted tuns exist within the field winding |
| BR | 2 | 2034 | 71 | -10 | 61 | armature winding is 52 years old, design life is 30 years<br>generator is regularly inspected, no know issues |
| BR | 3 | 2035 | 64 | 7 | 71 | armature winding replaced in 2012, design life is 30 years<br>core iron replaced in 2012, expected life is 30 years<br>generator field rewind & minor repairs scheduled for 2018 |
| GH | 1 | 2034 | 60 | 3 | 63 | armature winding replaced in 2007, design life is 30 years<br>core iron replaced in 2007, expected life is 30 years |
| GH | 2 | 2034 | 57 | 0 | 57 | generator is regularly inspected, no know issues<br>armature rewind kit is availble |
| GH | 3 | 2037 | 56 | 0 | 56 | generator is regularly inspected, no know issues<br>armature rewind kit is availble |
| GH | 4 | 2038 | 54 | 0 | 54 | generator is regularly inspected, no know issues<br>armature rewind kit is availble |

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**Case No. 2021-00393**

**Question No. 2.19**

**Responding Witness: Stuart A. Wilson**

Q-2.19. Please confirm that 2035 was the only year modeled in PLEXOS. If not, which years were modeled?

A-2.19. Confirmed.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
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**Case No. 2021-00393**

**Question No. 2.20**

**Responding Witness: Stuart A. Wilson**

Q-2.20. Please refer to the PLEXOS input files named "EFORMW_2021BP" and "EFORProb_2018BP".

a. Please explain how PLEXOS interprets the values reported in both workbooks.

b. Please explain if forced outages were modeled in PLEXOS for any units other than the coal units.

A-2.20.

a. The two files work together to define the probability (shown in the "EFORMW_2021BP" file) of each unit being fully available, fully unavailable, or derated across a range of operating levels (shown in the "EFORProb_2021BP" file).[13] For example, for Brown 3, the files indicate that there is:
   - 7.1% likelihood of the unit having 0 MW available (i.e., fully unavailable),
   - 3.1% likelihood of 140 MW available,
   - 0.2% likelihood of 226 MW available,
   - 0.1% likelihood of 256 MW available,
   - 0.1% likelihood of 336 MW available,
   - 0% likelihood of 376 MW available, and
   - 89.4% likelihood of 416 available (i.e., fully available).

b. Forced outages were modeled in PLEXOS for gas units as a single outage rate. These rates were entered directly in PLEXOS's user interface and were provided in the file provided in response to JI 1-3 at the following path.[14]

   \0283_2021IRP\ResourceAssessment\PLEXOS\20211008_2021IRP - 26WRM scenarios\20210920_2021IRP.xml

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[13] Note that the Companies did not provide a file named "EFORProb_2018BP." The Companies assume that this question should refer to the file named "EFORProb_2021BP."
[14] This is a PLEXOS system file, which requires the PLEXOS software to read.

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**Case No. 2021-00393**

**Question No. 2.21**

**Responding Witness: Stuart A. Wilson**

Q-2.21. Please refer to the PLEXOS input file named "FirmCapacityWinter". It does not appear that the firm capacity for the 4 and 8 hour battery storage resources are contained within this file. Please explain where the "FirmCapacityWinter" is captured in the inputs for the battery storage resources.

A-2.21. The firm capacities of batteries are entered directly via PLEXOS's user interface and were provided in the file provided in response to JI 1-3 at the following path.[15]

\0283_2021IRP\ResourceAssessment\PLEXOS\20211008_2021IRP - 26WRM scenarios\20210920_2021IRP.xml

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[15] This is a PLEXOS system file, which requires the PLEXOS software to read.

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**Case No. 2021-00393**

**Question No. 2.22**

**Responding Witness: Stuart A. Wilson**

Q-2.22. Please refer to the PLEXOS input file named "LzldStayOpenCosts."

a. Please provide the supporting workbook, with all formulas and links intact, used to develop the costs that are contained within this workbook.

b. Please provide the units for the values within this workbook.

c. Please confirm that the costs for existing units represent ongoing fixed O&M and capital maintenance and the costs for new units represent initial capital expenditures and ongoing fixed O&M. If anything but confirmed, please explain in full.

d. Please provide the basis for the assumed capital cost of new units.

A-2.22.

a. The supporting workbooks were provided in response to JI 1-3 at the following file paths:
   - Existing Units: \0283_2021IRP\ResourceAssessment\20210824_CoalUnitStayOpenCosts_0283D03.xlsx
   - New Units: \0283_2021IRP\SupplySideScreening\CONFIDENTIAL_20210819_2021IRPScreeningModel_0283D05.xlsx

b. The units are $/kW-year.

c. Confirmed.

d. The new units' capital cost assumptions were based on the National Renewable Energy Laboratory's 2021 Annual Technology Baseline. See the *2021 IRP Long-Term Resource Planning Analysis*, p. 11.

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**Case No. 2021-00393**

**Question No. 2.23**

**Responding Witness: Stuart A. Wilson**

Q-2.23. Please refer to the PLEXOS input file named "2021BP_VOM". Please explain why there is no variable O&M modeled for the resources named "New SCCT" and "New SCCT 2028".

A-2.23. The variable O&M reflected in this file represents reagents used for environmental controls, such as ammonia for SCRs, which do not apply to any existing SCCTs and are assumed not to apply to new SCCTs. Major maintenance events for SCCTs are typically a function of unit starts, so the Companies reflect a variable maintenance cost for SCCTs through use of a start cost penalty to act as an accrual toward a major maintenance event. The Companies use the "Start Penalty" variable in PLEXOS to ensure that the major maintenance frequency is consistent with utilization of new and existing SCCTs.

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**Question No. 2.24**

**Responding Witness: Stuart A. Wilson**

Q-2.24. Please refer to the PLEXOS input file named "RunningCostOpCharge".

a. Please provide the units for the values reported in this workbook.

b. Please describe what the costs in this workbook represent in PLEXOS.

A-2.24.

a. The unit for this variable is dollars per operating hour.

b. These costs represent an accrual toward major maintenance costs. For example, the representative NGCC unit would require an overhaul roughly every 35,000 operating hours at an estimated cost of $15 million in 2026 dollars. The Companies use this variable in PLEXOS to ensure that the overhaul frequency is consistent with hourly utilization of new NGCC units and Cane Run 7.

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**Question No. 2.25**

**Responding Witness: Stuart A. Wilson**

Q-2.25. Please refer to the PLEXOS input file named "2021BP_PJMPrice". Please explain if a PJM market interaction was modeled in PLEXOS.

A-2.25. PJM market interaction was not modeled in PLEXOS for the 2021 IRP.

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**Case No. 2021-00393**

**Question No. 2.26**

**Responding Witness: Stuart A. Wilson**

Q-2.26. Please refer to the PLEXOS output file named "CONFIDENTIAL_659", worksheet named "Fuel". Please explain why the "New SCCT" and "New SCCT 2028" do not have fuel reported in this worksheet.

A-2.26. The fuel prices for these units are assumed to be the same as the Companies' existing Cane Run 7 unit.

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**Question No. 2.27**

**Responding Witness: Stuart A. Wilson**

Q-2.27. Please refer to the PLEXOS output file named "CONFIDENTIAL_659", worksheet "Gen". Please explain why the "New SCCT" has a value reported for the "FO&M" field, but the "New SCCT 2028" does not.

A-2.27. All generation portfolios in the IRP were developed to include at least two SCCTs for the purpose of supporting lower $CO_2$ emissions. SCCT units have lower $CO_2$ emissions than coal units, which would provide the majority of charging energy for battery storage if battery storage was utilized in the cases modeled for peaking capacity. This assumption has very little impact on the IRP results. With the exception of two low load cases, all resource plans include more than two new SCCTs. In Plexos, fixed O&M for these two SCCTs (labeled "New SCCT 2028") is zero because they are included in all cases. In calculating fixed O&M in Table 8-9 of Volume I and revenue requirements in Table 9-1 of Volume I for the base load, base fuel price case, fixed O&M is the same as other SCCTs.

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**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.28**

**Responding Witness: Stuart A. Wilson**

Q-2.28. Please refer to the PLEXOS output files. Please explain what the folders named "669" and "673" represent.

A-2.28. These were PLEXOS testing runs that were completed after the 2021 IRP was filed and are unrelated to the 2021 IRP. These files were inadvertently provided with the 2021 IRP files and can be ignored.

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**Question No. 2.29**

**Responding Witness: Stuart A. Wilson**

Q-2.29. Please explain what the PLEXOS file "mttr_2021BP.csv" is intended to represent?

A-2.29. The file contains input data for the duration of forced outages in hours. "mttr" stands for mean time to repair.

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**Case No. 2021-00393**

**Question No. 2.30**

**Responding Witness: Stuart A. Wilson**

Q-2.30. Please explain why the Companies did not model significantly differing winter versus summer capacities for most existing thermal units but did so for new thermal resources?

A-2.30. The Companies model winter and summer capacities consistent with expected unit ratings. The differences between winter and summer maximum capacities are typically smaller for coal-fired units than they are for gas-fired units, and because all new thermal generation in the 2021 IRP is gas-fired, the winter and summer capacities will have a higher difference than with existing coal resources.

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**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.31**

**Responding Witness: Stuart A. Wilson**

Q-2.31. Please refer to the file "LzldStayOpenCosts".

a. Were the new resources contained in the referenced file the only ones that passed through the resource screening analysis? Please explain.

b. What was the rationale for screening out the other resources?

c. If other resources not included in "LzldStayOpenCosts" passed the screening please explain how they were evaluated in PLEXOS.

A-2.31.

a. Yes. The resource screening analysis was performed to develop a set of potential resources that had the potential to be included in the long-term expansion plan and thereby, PLEXOS. It was unnecessary to model other technologies in PLEXOS, so the Companies did not create levelized cost inputs for those technologies.

b. See the *2021 IRP Resource Screening Analysis* in Volume III if the 2021 IRP. Section 3 explains the rationale for each technology not chosen for further evaluation.

c. Other resources were not evaluated in PLEXOS.

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**Case No. 2021-00393**

**Question No. 2.32**

**Responding Witness: Stuart A. Wilson**

Q-2.32. In response to JI Q1-4(c), the Companies stated, "The capacity expansion plans were optimized to meet minimum reserve margin requirements for both summer and winter. Specifically, Plexos was used to identify the least-cost generation portfolio that meets minimum reserve margin constraints (i.e., 17 percent in the summer and 26 percent in the winter) at the end of the IRP planning period. Then, an annual resource plan was developed to meet minimum reserve margin constraints throughout the planning period."

a. How were these constraints represented, e.g., as constraints applying to all "summer" months and all "winter" months, as constraints in the peak summer and peak winter months?

b. Was PLEXOS able to simultaneously solve for a summer and winter reserve margin constraint? Please explain in full.

A-2.32.

a. The Companies modeled the constraint as a minimum level of reserves in MW required to meet the annual peak based on the minimum reserve margin targets.

b. PLEXOS does have the ability to solve for both summer and winter reserve margins when run on a quarterly period basis, which requires significantly longer run times. Therefore, the Companies ran PLEXOS as described in part (a) and manually checked that the target reserve margins were met for both winter and summer in all scenarios.

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**Case No. 2021-00393**

**Question No. 2.33**

**Responding Witness: Stuart A. Wilson**

Q-2.33. Please refer to the PROSYM input and output files in the folder named "ReferenceCase".

a. Please confirm that PROSYM was used to perform production cost modeling for each of the nine expansion plans developed from the PLEXOS modeling. If anything but confirmed, please explain your response in full.

b. If additional production cost runs were performed in PROSYM, please provide the modeling input and output files for those runs.

c. If only "ReferenceCase" run was used to derived the production cost results included in the revenue requirements for each portfolio please explain how that was done and indicate which cell references, tabs, etc. were used.

A-2.33.

a. Not confirmed. The Companies only ran detailed hourly production cost modeling in PROSYM for the Base Load, Base Fuel case (referred to in some files as the Reference Case).

b. No additional production cost runs were completed for the 2021 IRP. See the response to Question No. 2.36(b).

c. The Companies ran PROSYM using the "2022BP.ctl" file and related text files in the "ModelInputs" subfolder and read results using the "ProsymCaseDeveloper_LoadSim.egp" SAS program. Within the SAS program, the Companies used the "Read_BPSummary" ordered list to read and summarize results, which created the .csv and .sas7bdat files as outputs in the "ReferenceCase" directory. The production cost components of revenue requirements for this portfolio are available at a system level in the "out_stationyr.csv" file as "SysCost" in column D.

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**Question No. 2.34**

**Responding Witness: Stuart A. Wilson**

Q-2.34. Please confirm if the production cost runs performed within PROSYM were dispatched to load or to price.

A-2.34. Production cost runs in PROSYM are performed to minimize the production cost of serving load.

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**Question No. 2.35**

**Responding Witness: Stuart A. Wilson**

Q-2.35. Please refer to workbook named "CONFIDENTIAL_20210923_2021IRPResPlanModel_0283D04", worksheet named "NREL" and the Companies response to Joint Intervenors' requests 1.54 subpart d and 1.55 subpart a, where it stated that the Company modeled solar and battery storage resources with the Investment Tax Credit "ITC".

a. Please provide a cell reference that shows how ITC is applied to the cost of new solar and battery storage resources in this workbook.

A-2.35.

a. In the referenced workbook, solar costs were modeled with the $28.05/MWh levelized cost that incorporates the ITC (see cells in column BD, rows 26 and 58-71 in the "Resources" worksheet). This cost was computed in a separate file provided in response to JI 1-3 – 0283_2021IRP\SupplySideScreening\CONFIDENTIAL_20210819_2021IRPScreeningModel_0283D05.xlsx. In the "SSSModel" worksheet, changing the value in Cell E7 to "1," the Generation Alternative in Cell C10 to "4," and the 1st Year of Fixed Period in Cell C12 to "2031," results in a LCOE value in Cell C48 of $28.05/MWh. Cell T30 in the "Resources" worksheet shows the 26% ITC assumption.

The same file was used to compute the levelized cost of battery storage as an input for Plexos. For example, for 4-hour battery storage, changing Cell T34 in the "Resources" worksheet to "26%," and in the "SSSModel" worksheet, changing Cell E7 to "2," the Generation Alternative in Cell C10 to "8," and the 1st Year of Fixed Period in Cell C12 to "2031," results in a Levelized Cost of Capacity value in Cell C49 of $104,535/MW-Yr. This value matches the assumption used in Plexos, as shown in Column O of 0283_2021IRP\ResourceAssessment\PLEXOS\20211008_2021IRP - 26WRM scenarios\LvlzdStayOpenCosts.csv. All generation portfolios developed in Plexos assume a 26% ITC for battery storage.

The originally referenced file was used to compute capital costs in Table 8-8 of Volume I, Fixed O&M in Table 8-9 of Volume I, and revenue requirements in Table 9-1 of Volume I for the base load, base fuel price case. Capital costs and Fixed O&M appropriately do not reflect the impact of the ITC, but the calculation of revenue requirements beginning in 2035, the year storage is first added in the base load, base fuel price case, should reflect the impact of the ITC to be consistent with assumptions in the Long-Term Resource Planning Analysis. The following table provides updated values in 2035 and 2036 as well as an updated present value of revenue requirements for Table 9-1.

**Update to Table 9-1**

| | **Original** | | **Update** | |
|---|---|---|---|---|
| | **2035** | **2036** | **2035** | **2036** |
| Revenue Requirements ($M) | 1,502 | 1,555 | 1,499 | 1,548 |
| PVRR ($M; 2021 Dollars) | 3,821 | | 3,809 | |
| Base Energy Requirements (GWh) | 31,326 | 31,492 | 31,326 | 31,492 |
| cents/kWh | 4.80 | 4.94 | 4.78 | 4.91 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.36**

**Responding Witness: Stuart A. Wilson**

Q-2.36. Please refer to the workbook named "CONFIDENTIAL_20210923_2021IRPResPlanModel_0283D04", worksheet named "PROSYM".

a. Please explain what the column named "Iter" represents.

b. Please confirm what PROSYM production cost runs were included in the column named "SysCost".

c. Please explain why the costs modeled in the column named "SysCost" do not seem to match the costs reported in the PROSYM output file named "out_stationyr".

A-2.36.

a. "Iter" is an abbreviation for iteration. This is simply an index label for a distinct production cost run.

b. Prior to the IRP analysis, the Companies considered developing a makeshift expansion planning tool utilizing bulk processing of PROSYM production cost runs. The PROSYM production cost runs on this tab are left over from this unsuccessful and incomplete effort and were not used in the IRP. Only a portion of this model's functionality was used to develop the IRP. See the response to Question Nos. 2.33 and 2.35.

c. See the response to part (b).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.37**

**Responding Witness: Stuart A. Wilson**

Q-2.37. Please refer to the workbook named "CONFIDENTIAL_20210923_2021IRPResPlanModel_0283D04", worksheet named "Detail".

a. Please explain what the difference is between the stay-open capital and O&M reported in rows 3073 to 3140 and the stay- open capital and O&M reported in rows 1505 to 1572.

b. Please explain what the 1 and 2 mean in the column named "Case".

A-2.37.

a. The referenced model gives the user the ability to compare costs for two cases. The values in rows 1505 to 1572 reflect input assumptions for Case 1; the values in rows 3073 to 3140 reflect input assumptions for Case 2. The calculated values in the two sections are the same because the input assumptions for Cases 1 and 2 are the same. Only a portion of this model's functionality was used to develop the IRP. See the response to Question No. 2.35.

b. The 1 and 2 in the "Case" column refers to the case number.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.38**

**Responding Witness: Stuart A. Wilson**

Q-2.38. Please refer to the workbook named "CONFIDENTIAL_20210923_2021IRPResPlanModel_0283D04", worksheet named "Profiles". Please provide the supporting workbook, with all formulas and links intact, used to develop the profiles reported in rows 3 to 25.

A-2.38. See attachment being provided in Excel format. This file was inadvertently omitted from the response to JI 1-3.

The attachment is being provided in a separate file in Excel format.

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.39**

**Responding Witness: Stuart A. Wilson**

Q-2.39. Please refer to the spreadsheet entitled"20210924_ScarcityPricingFigure_0283" provided in response to JointIntervenors' First Set of Discovery. With respect to this spreadsheetplease answer the following questions:

a. Please confirm that only tabs "Scarcity Data" and "Chart1" were used for this IRP. If that is not the case, what were theother tabs used for?

b. What is the source of data in the tab "Scarcity Data"?

c. What do the data in each of the columns in the tab "ScarcityData" represent?

d. What are the units for each of the columns in the tab "ScarcityData"?

e. Why were these data used to develop scarcity prices?

f. Please provide the workbook(s) used to support and/or develop the data in the tab "Scarcity Data".

g. Please provide any data in the Companies' possession that characterizes both the number of hours in the 2025 SERVM simulation in which scarcity pricing would apply and which scarcity price applied.

A-2.39.

a. Confirmed.

b. The pricing curve was developed based on the Companies' actual purchases over a range of reserve conditions and extrapolated to tighter reserve conditions. The values were inflated to 2025 dollars and capped at the cost of unserved energy.

c. Only columns L and M in the "Scarcity Data" tab were used for this IRP. Column L represents reserve capacity in excess of hourly load and is expressed as a percentage. Column M represents scarcity prices in $/MWh.

d. See the response to part (c).

e. See the response to part (b).

f. The scarcity price curve was jointly developed by the Companies and Astrape (the developer of SERVM). The Companies do not possess any workbooks.

g. The Companies do not have hourly SERVM output data.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.40**

**Responding Witness: Stuart A. Wilson**

Q-2.40. With respect to the PROSYM files used to perform the RTO analysis contained in Volume III of the IRP please answer the following questions:

a. How do the case names: 0_2022BP, 1_CTRule, 2_SpinRes, 3_RTOExp, 4_TransExp, 5A_PurAdder, 5B_OSSAdder, 6_SpliGenLoad, 7_Losses, 8_NoCT, and 9PJMB relate to the RTO analysis conducted?

b. For each case name identified in response to subpart a above, please explain (i) what each case name means and (ii) what each case was used for?

c. Please explain how the data in the folder with the file path 2021RTOAnalysis/PROSYM relate to the calculation of benefits and costs contained in RTOCostAnalysis_2021. Be specific including giving specific filepath and cell references for the data that are utilized in the RTOCostAnalysis_2021 spreadsheet.

A-2.40.

a. The cases were created in incremental steps by making one cumulative input change for each case to assess the reasonableness of the results. See Section 8.2 of the 2021 RTO Membership Analysis for the changes made to PROSYM to reflect RTO membership.

b. See the table below.

| **Case Number** | **Purpose** |
|---|---|
| 0_2022BP | 2022 Business Plan as the starting case |
| 1_CTRule | Remove an existing modeling constraint on starting CTs for making market sales |
| 2_SpinRes | Reduce spinning reserve from 327 MW to 220 MW |
| 3_RTOExp | Eliminate existing RTO expenses on market transactions |
| 4_TransExp | Eliminate transmission expenses on market transactions |
| 5A_PurAdder | Eliminate purchase price hurdle rate |
| 5B_OSSAdder | Eliminate off-system sale price hurdle rate |
| 6_SpliGenLoad | Split generating units from serving native load to model RTO configuration |
| 7_Losses | Eliminate transmission losses |
| 8_NoCT | Eliminate new planned CTs |
| 9PJMB | PJM membership base case |

c. "CONFIDENTIAL_20211009_out_unityr(RTOFullHedge,RTONoHedge).xlsx" was used for costs and benefits analysis in Appendix C of the 2021 RTO Membership Analysis. Specifically, cells in the range of A75-G102 in the tab "BaseLoad(FullHedge)" were used.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.41**

**Responding Witness: Stuart A. Wilson**

Q-2.41. Please refer to the spreadsheet entitled "20211002_TablesforReliabilityAnalysisD06" provided in response to Joint Intervenors' First Set of Discovery.

a. Provide the workbook(s) with all formulas and links intact used to develop the Stay-Open and Overhaul costs in the tab "Stay- Open Cost".

A-2.41.

a. See attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.42**

**Responding Witness: Stuart A. Wilson**

Q-2.42. Please refer to the spreadsheet entitled "MHC_Joint DR1 Attach to Q80(a)" provided in response to Joint Intervenors' First Set of Discovery.

a. Please explain how these data were used to develop the available transmission capacity ("ATC") assumptions in the SERVM modeling.

b. Provide, with all formulas and links intact, any workbook(s) used to translate these data into ATC assumptions in the SERVM modeling.

c. Please explain why these particular time periods were chosen to develop the ATC assumptions.

d. Please explain what the data in columns D – G and I – K represent? E.g. are these physical import and export limits, historical emergency energy transactions, historical flows between regions (for any reason), etc.?

e. Please provide the hourly ATC assumptions used in this modeling.

A-2.42.

a. The data was imported into SERVM with each data point having the same likelihood of being randomly drawn.

b. No workbooks were used for this purpose.

c. These time periods represent the most recent three years of summer and winter weekday periods when peak demands are most likely to occur.

d. They represent physical export and import capability for each neighboring region for each specific date.

e. No hourly ATC assumptions were used.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Initial Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.43**

**Responding Witness: Stuart A. Wilson**

Q-2.43. Please refer to the spreadsheet entitled "Monthly Results" provided in response to Joint Intervenors' First Set of Discovery (filepath JI-1 Confidential/WorkpapersCONFIDENTIAL/0283_2021IRP/ReserveMargin/SERVM/SERVM_Run/20211004). With respect to this spreadsheet please answer the following:

a. Please define each of the following terms: EUE_Capacity, EUE_Intrahour, EUE_Multihour, LOLE_Capacity, LOLE_Intrahour, LOLE_Multihour, LOLH_Capacity, LOLH_Intrahour, and LOLH_Multihour.

b. What is the "Probability" in Column G of tab "SMMA_2021IRP_RetM2(Combined)" measuring? Please explain in full.

c. Cells B21:K23 of tab "Sheet1" correspond with the reported LOLE values in Table 15 of the Reserve Margin Analysis. These cells are derived from the pivot table in columns A – L which show the sum of "ProbWeightedLOLE*10". Is the multiplication by 10 intended to represent 10 years? If not, what does it represent?

d. Are the LOLE values reported on tab "Sheet1" in units of events or hours? If events, what does it mean to have a partial event (value < 1)?

e. If the answer to subpart c is "yes", are the reported LOLE results on tab "Sheet1" intended to represent LOLE over a 10-year period? Please explain in full.

A-2.43.

a. See the table below.

| **Term** | **Definition** |
|---|---|
| EUE_Capacity | Expected unserved energy due to capacity shortage |
| EUE_Intrahour | Expected unserved energy due to ramping constraints not identified 1 hour prior to the hour being simulated |
| EUE_Multihour | Expected unserved energy due to ramping constraints identified >1 hour prior to the hour being simulated |
| LOLE_Capacity | Count of days with EUE_Capacity |
| LOLE_Intrahour | Count of days with any EUE_IntraHour |
| LOLE_Multihour | Count of days with any EUE_Multihour |
| LOLH_Capacity | Count of hours with EUE_Capacity |
| LOLH_Intrahour | Count of hours with any EUE_IntraHour |
| LOLH_Multihour | Count of hours with any EUE_Multihour |

b. The analysis used 48 hourly demand forecasts for 2025 based on actual weather in each of the last 48 years. The probability in Column G represents the likelihood of each weather year occurring in 2025, which is assumed to be the same for all 48 weather years.

c. Yes.

d. See the response to part a. LOLE values are the count of days with unserved energy and are expressed as an average over 300 iterations.

e. Yes. The estimated LOLE was multiplied by 10 for convenient comparison to the 1-in-10 guideline.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.44**

**Responding Witness: Stuart A. Wilson**

Q-2.44. Please refer to Tables 14 and 15 of the Reserve Margin Analysis. With respect to this spreadsheet please answer the following:

a. How is LOLE being measured? In events or hours?

b. If LOLE is being measured in hours how is 1 in 10 standard being applied to these results? As no more than 2.4 hours in 2025 or in some other way? Please explain in full.

c. If LOLE is being measured in events, how is the 1 in 10 standard being applied to these results? Please explain in full.

A-2.44.

a. See the response to Question No. 2.43(d).

b. The industry standard of 1-in-10 LOLE physical reliability guideline means 1 day in 10 years. Therefore, in Tables 14 and 15, the generation portfolio that has LOLE of 1 meets the 1-in-10 guideline. Note that the study year of the IRP analysis was a single year (2025). However, for convenient comparison to the 1-in-10 guideline, the estimated LOLE was multiplied by 10.

c. See the responses to parts (a) and (b).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.45**

**Responding Witness: Stuart A. Wilson**

Q-2.45. The Reserve Margin Analysis at page 24 states, "Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85th and 90th percentiles (%-ile) of the reliability and generation production cost distribution."

a. Please identify which files provided in response to Joint Intervenors' initial discovery requests show how these calculations were made?

b. If all the files necessary to reproduce these calculations were not provided in response to Joint Intervenors' initial discovery requests, please provide them with all formulas and links intact.

A-2.45.

a. Following files were used for the calculations:

1. "\ReserveMargin\20211002_TablesforReliabilityAnalysisD06.xlsx"
   See "Table12to16" tab.

2. "\ReserveMargin\ELDC\CONFIDENTIAL_20210820_CHW_SeasonalELDC_WYLoad20210831_ReserveMarginMax_0283D03.xlsx"
   See "PivotCost" tab.

3. "\ReserveMargin\SERVM\SERVM_Run\20211004\MonthlyResults.xlsx"
   See "Sheet1" tab.

b. See the response to part (a). All files were provided in response to the initial request.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.46**

**Responding Witness: Stuart A. Wilson**

Q-2.46. Please provide the forced outage rate assumptions and the ancillary service requirements enforced in the SERVM modeling.

A-2.46. See Table 3 in 2021 IRP Reserve Margin Analysis for forced outage rate assumptions. Ancillary service requirement is 252 MW. Note that no workbooks were provided for these inputs because they were directly inputted via the SERVM interface.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.47**

**Responding Witness: David S. Sinclair**

Q-2.47. The Company's response to JI Q-1.11 says in part, "See Table 20 on page 22 of the '2021 IRP Long-Term Resource Planning Analysis' in the IRP Volume III. The CO2 emissions reduction forecasted for the base IRP scenario reflects a PPL-wide reduction of 68% by 2035." The referenced table shows reductions of 22 – 47% by 2035. Please explain how the Company determined a 68% reduction by 2035 would be achieved. Provide any workbooks supporting your response in electronic format with all formulas and links intact.

**Table 20: Forecasted $CO_2$ Emissions vs. 2010 Actuals**

| Scenario | Year | $CO_2$ Emissions (short tons) | % Change from 2010 |
|---|---|---|---|
| 2010 Actual | 2010 | 35,843 | -- |
| Base Load, Base Fuel Prices | 2035 | 21,505 | -40% |
| Base Load, High Fuel Prices | 2035 | 19,692 | -45% |
| Base Load, Low Fuel Prices | 2035 | 25,100 | -30% |
| High Load, Base Fuel Prices | 2035 | 22,831 | -36% |
| High Load, High Fuel Prices | 2035 | 20,636 | -42% |
| High Load, Low Fuel Prices | 2035 | 28,079 | -22% |
| Low Load, Base Fuel Prices | 2035 | 20,619 | -42% |
| Low Load, High Fuel Prices | 2035 | 19,155 | -47% |
| Low Load, Low Fuel Prices | 2035 | 22,992 | -36% |

A-2.47. See attachment being provided in Excel format. The percentage changes in Table 20 are based on the Companies' generation alone. The reduction in the base load, base fuel price case is 68% based on a PPL company-wide 2010 baseline of 62,577 metric tons.

The attachment is being provided in a separate file in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.48**

**Responding Witness: Stuart A. Wilson**

Q-2.48. Please refer to the spreadsheet entitled "20211002_TablesforReliabilityAnalysisD06" provided in response to Joint Intervenors' First Set of Discovery.

a. Please explain why there is a difference between frequency (every few years) of the overhaul costs given in tab "Stay-Open Cost" and the annual, historical capital costs by units given in response to JI 1-17(d).

b. Will the overhaul costs given in tab "Stay-Open Cost" be capitalized when they are recovered from ratepayers? Please explain in full.

c. If the overhaul costs in the tab "Stay-Open Cost" are a different category of costs from the capital costs given in response to JI 1-17(d) please explain why annual capitalized maintenance was not accounted for as part of the Companies' stay-open costs.

A-2.48.

a. The frequency of turbine overhauls is typically once every 8 years, and this assumption is reflected in the stay-open cost forecast. Historical turbine overhauls may have deviated from that schedule depending upon unit performance and the timing of other maintenance projects.

b. Yes, these overhaul costs would be capitalized.

c. The "Stay-Open Cost" tab consists only of costs necessary to keep a unit online. The historical capital costs included in response to JI 1-17(d) include these costs as well as one-time expenses to meet environmental regulations, such as baghouses to comply with the Mercury and Air Toxics Standards rule, or expenses that will be incurred regardless of a unit's operational status, such as pond closures to comply with the CCR rule.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.49**

**Responding Witness: John Bevington**

Q-2.49. Please refer to the Companies' response to JI Q-1.41, which says in part, "[T]he Large Nonresidential Demand Conservation Program is open to industrial customers who have not opted out of DSM." Which respect to this statement please answer the following:

a. Please give a copy of the communication(s) typically sent to eligible opt-out customers describing the opt-out/in options.

b. Describe the process that a customer would take to opt back in to DSM programs.

c. Please explain why DR programs are subject to opt-out provisions, what rules, Commission orders, etc. apply?

d. Please explain how DSM cost-allocation works for customers who opt-in to DSM programs even though they are eligible to opt-out.

A-2.49.

a. – c. The Companies described their proposed industrial opt-in and opt-out procedures described in the Direct Testimony of David E. Huff in Case No. 2017-00441, and the relevant opt-out and opt-in forms were Exhibits REL-6 through REL-9 in the same proceeding.[16] The Commission approved the Companies' proposed industrial opt-in and opt-out approach in that proceeding.[18] The relevant statute is KRS 278.285(3).

d. See the Companies' electric tariffs at Sheet Nos. 86 – 86.7

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[16] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

[18] Case No. 2017-00441, Order at 32-33 (Ky. PSC Oct. 5, 2018), available at https://psc.ky.gov/pscscf/2017%20Cases/2017-00441//20181005_PSC_ORDER.pdf.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILTIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.50**

**Responding Witness: Stuart A. Wilson**

Q-2.50. Refer to the Companies' response to PSC Q-1.13 which says in part, "The load forecast implicitly assumes these efficiency improvements will continue throughout the IRP analysis period."

a. Please explain why the Company believes the load forecast accounts for efficiency improvements throughout the IRP analysis period.

b. Please provide any workbook(s) in electronic format with all formulas and links intact that support your answer.

c. What were the Companies' annual incremental peak and MWh savings from DSM during historical period used to develop the load forecast model?

A-2.50.

a. As mentioned in the first two sentences of the response to PSC 1-13(a), the Companies' DSM-EE programs are not modeled explicitly. Energy efficiency improvements from DSM programs and customer-initiated actions are included in the historical data used to specify the Companies' load forecast models. The Companies do not add the energy estimated to be reduced by DSM programs back to the historical data used to specify the forecast models. Therefore, to the extent that DSM-EE impacts historical trends recognized in model specification, it will also have that impact moving forward.

b. N/A.

c. See response to part (a). See Table 7-14 in IRP Vol. I for the estimated historical DSM energy and demand savings, but again, this data was not used to adjust historical data used to specify the forecast models.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.51**

**Responding Witness: David S. Sinclair**

Q-2.51. According to Table 8-17, Volume I, p.105 pdf, the Companies' generation resource mix would continue to rely heavily on coal and natural gas through 2036. The generation mix supplied from coal and natural gas is proposed to decline from 96.6% in 2021 to 91.1% in 2030 and 79.0% in 2036.

a. Explain how the Companies reconcile this plan with Louisville Metro's 100% Renewable Energy Commitment.

b. Explain how the Companies reconcile this plan with their parent company PPL's commitment to reduce emission 70% by 2035 (relative to 2010 emissions), 80% by 2040, and 100% by 2050.

A-2.51.

a. As noted in part b of this request, the Companies' parent company, PPL, has announced goals for significant $CO_2$ emission reductions in the next few decades. In addition, the Companies already own and operate the Brown Solar Facility and the Ohio Falls and Dix Dam hydro facilities, have contracted for additional solar generation, offer Green Tariff Option #3, and are expanding their facilities to offer the Solar Share Program to additional customers who desire to increase renewable generation even further. In doing so, the Companies are already moving in ways that are consistent with Louisville Metro's renewable energy goals.

Regarding those goals, it is helpful to be clear about what Louisville Metro's "Resolution of 100% Clean Renewable Electricity for Metro Government Operations by 2030, 100% Clean Energy for Metro Government Operations by 2035 and 100% Clean Energy Community-Wide by 2040" actually says and does. (A copy of the resolution is attached.) Notably, the resolution states Metro Council's *support* for the goals recited in the resolution's title; it does not *mandate* achieving such goals.[20] In addition, the resolution explicitly

[20] Resolution Section I.

recognizes economic constraints in meeting such goals: "Metro Council adds to its priorities *as Metro budget allows* … adding renewable energy infrastructure to reduce Louisville Metro's energy needs and carbon footprint and meet established Climate Action Plan goals…."[21] Therefore, although Louisville Metro established aggressive goals in its resolution, it also acknowledged practical constraints in meeting them.

To help Louisville Metro meet its goals, the Companies have engaged in numerous meetings and conversations with Metro officials regarding the first two of the resolution's goals, which apply only to Metro government operations. Specifically, the Companies discussed with Metro government officials ideas and concepts that they could pursue to accomplish their goals for their own operations, including the volume of natural gas usage that would need to convert to electricity to be consistent with the resolution.

With regard to the resolution's goal of "100% clean energy … community-wide by 2040," it is important to note that the resolution states that "a community is powered with 100% renewable energy when the amount of energy generated from renewable energy source equals or exceeds 100% of the annual energy consumed within the community."[22] In other words, meeting the resolution's goal for the community does *not* require that all of the community's energy supply be renewable in real time, but rather that the renewable energy resources serving the community produce at least as much energy on an annual basis as the community consumes on an annual basis. Therefore, Louisville Metro's goal does not preclude using non-renewable resources to supply the community's energy requirements at any given moment.

Finally, the IRP focuses on serving customers' energy needs at all moments of the year, not just annually. Thus, the Companies have not evaluated a resource plan that focuses only on annual energy needs.

b. See the response to SREA 2-18.

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[21] Resolution Section III.
[22] Resolution page 1 ("WHEREAS, according to the Sierra Club, "[al community is powered with 100% renewable energy when the amount of energy generated from the renewable energy source equals or exceeds 100% of the annual energy consumed within the community."").

RESOLUTION NO. 009, SERIES 2020

**A RESOLUTION FOR 100% CLEAN RENEWABLE ELECTRICITY FOR METRO GOVERNMENT OPERATIONS BY 2030, 100% CLEAN ENERGY FOR METRO GOVERNMENT OPERATIONS BY 2035 AND 100% CLEAN ENERGY COMMUNITY-WIDE BY 2040 (AS AMENDED).**

**SPONSORED BY: COUNCILMEMBERS COAN, GEORGE, AND HOLLANDER**

**WHEREAS**, "clean renewable electricity" is defined as electricity that: (1) can be extracted, generated, transported, and consumed with neutral carbon emissions or no emissions at all, and with no current or future significant threat to life and the natural environment; and (2) is generated and stored from renewable resources, which are naturally replenished on a human timescale, such as sunlight, wind, geothermal, tides, and, conditionally, bio-matter and various forms of hydropower. "Clean energy" encompasses electricity, transportation, buildings, and food systems; and

**WHEREAS**, according to the Sierra Club, "[a] community is powered with 100% renewable energy when the amount of energy generated from the renewable energy source equals or exceeds 100% of the annual energy consumed within the community."

**WHEREAS**, overwhelming scientific evidence affirms the existence of climate change and that the primary cause of recent climate change is human combustion of fossil fuels; and

**WHEREAS**, climate change has already brought devastating impacts in our nation and globally and, if unchecked, will fundamentally undermine the stability of economic, natural, and social systems, including the possibility of massive disruptions to human life on Earth; and

**WHEREAS**, more frequent and severe flooding, storms, and droughts in our own region pose similar threats to the stability of the local environment and economy, including human health effects; and

**WHEREAS**, there is no credible path to a safe climate that includes continued long-term combustion of fossil fuels and the proliferation of new fossil fuel infrastructure; and

**WHEREAS**, air pollution in the form of ozone and fine particulate matter brings about 46 deaths and 49,000 missed days of work or school in the Louisville metro area annually; and

**WHEREAS**, existing technologies have served this city well for over 100 years, but newer technologies suited for current and future conditions are now available; and

**WHEREAS**, local, state, and national economies are rapidly transitioning to 100% clean renewable energy along with multinational corporations and countries and cities globally; and

**WHEREAS**, Louisville Metro Government wishes to take full advantage of the new 21$^{st}$ century energy economy; and

**WHEREAS**, the Mayor is a signatory to the Mayors' Pledge to support the Paris Climate Agreement and the Mayor's Climate Compact to reduce greenhouse gas emissions, and the Metro Council unanimously adopted Resolution 079, Series 2015 to expand solar energy and efficiency in the city; and

**WHEREAS**, a just transition to 100% clean renewable energy will create high-quality local jobs; and

**WHEREAS**, youth and future generations will be more severely affected by climate change, and it is the duty of current leaders to act promptly and resolutely to mitigate climate change for their benefit; and

**WHEREAS**, low-income residents are often most burdened by energy costs and climate impacts, and Louisville Metro is committed to ensuring all residents enjoy the benefits of energy efficiency, clean renewable energy, electrified transportation, fair utility rates, and employment opportunities; and

**WHEREAS**, Louisville Metro's commitment to clean renewable energy will reduce carbon emissions and associated climate change, and reduce air pollution and associated public health risks and costs; and

**WHEREAS**, Louisville Metro's energy use could be substantially served by existing renewable energy and efficiency technologies and energy conservation at reasonable cost; and

**WHEREAS**, in 2017, 99% of electricity delivered to Louisville Metro consumers by utility companies was generated from fossil fuels – 80-90% coal and 9-19% natural gas – with only 1% from renewables; and

**WHEREAS**, given the accelerating rate of climate change, energy consumers, Louisville Metro, and utility companies must take strong action to quickly reduce carbon emissions and shift to 100% clean renewable energy for both Louisville Metro's operations and the entire community through technical and consumer changes that are within practical and economic reach; and

**WHEREAS**, achieving these energy goals will require broad input and concerted action from government, business, and community leaders, utilities, and individual citizens; and

**WHEREAS**, no one can predict what a final action plan will look like, one possible scenario might include: (a) reducing demand through conservation and energy efficiency policies and incentives; (b) creating electricity with many installations of solar panels on rooftops and solar farms; (c) creating storage for that electricity through batteries, phase change, and other upcoming technologies; (d) using the existing Ohio Falls Generating

Station; (e) importing wind power with power purchase agreements (PPAs); (f) during the transition period, using existing fossil fuel energy temporarily; (g) offsetting local fossil fuel generation by purchasing renewable energy credits, (h) replacing fossil fuel-powered vehicles with electric or biofuel-powered ones, either through conversion or incentives and devising more efficient and convenient public transportation; and (i) creating a renewable energy trust fund, green bank, or other innovative financing mechanisms.

**NOW, THEREFORE, BE IT RESOLVED BY THE LEGISLATIVE COUNCIL OF THE LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT ("METRO COUNCIL") AS FOLLOWS:**

**SECTION I**: Metro Council supports (1) a 100% clean renewable electricity goal for Metro Government operations by 2030, a 100% clean energy goal for Metro Government operations by 2035, and a 100% clean energy goal community-wide by 2040; ~~and~~ (2) the revision of all building codes for new construction to require energy efficiency, conservation, and renewable energy applications toward an eventual goal of net zero or net positive energy, water, and waste for Louisville Metro; and (3) the opening of free market pricing for electrical generation and guarantee of total cost access to the electrical grid in order to provide the public with cleaner and cheaper electricity.

**SECTION II**: Metro Council urges (1) Metro Government's forthcoming Climate Action Plan to support this goal; (2) public participation be prioritized in the planning, decision-making, and implementation process; and (3) underserved communities be brought into the political process to develop more just, equitable and sustainable energy systems and to facilitate more democratic ownership.

**SECTION III**: Metro Council adds to its priorities as Metro budget allows: (1) energy efficiency and conservation projects, programs and outreach plus adding renewable energy infrastructure to reduce Louisville Metro's energy needs and carbon footprint and meet established Climate Action Plan goals; and (2) energy resources and programs that benefit low-income residents and create more equity in energy use, rates and jobs in the community.

**SECTION IV**: This resolution shall take effect upon its passage and approval.

Sonya Harward
Metro Council Clerk

David James
President of the Council

Greg Fischer
Mayor

2/12/2020
Approval Date

**APPROVED AS TO FORM AND LEGALITY:**

Michael J. O'Connell
Jefferson County Attorney

By: ______________________

**LOUISVILLE METRO COUNCIL**
**ADOPTED**
February 6, 2020

R-102-19 Clean Energy Resolution (CAM on 12-5-19).docx

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

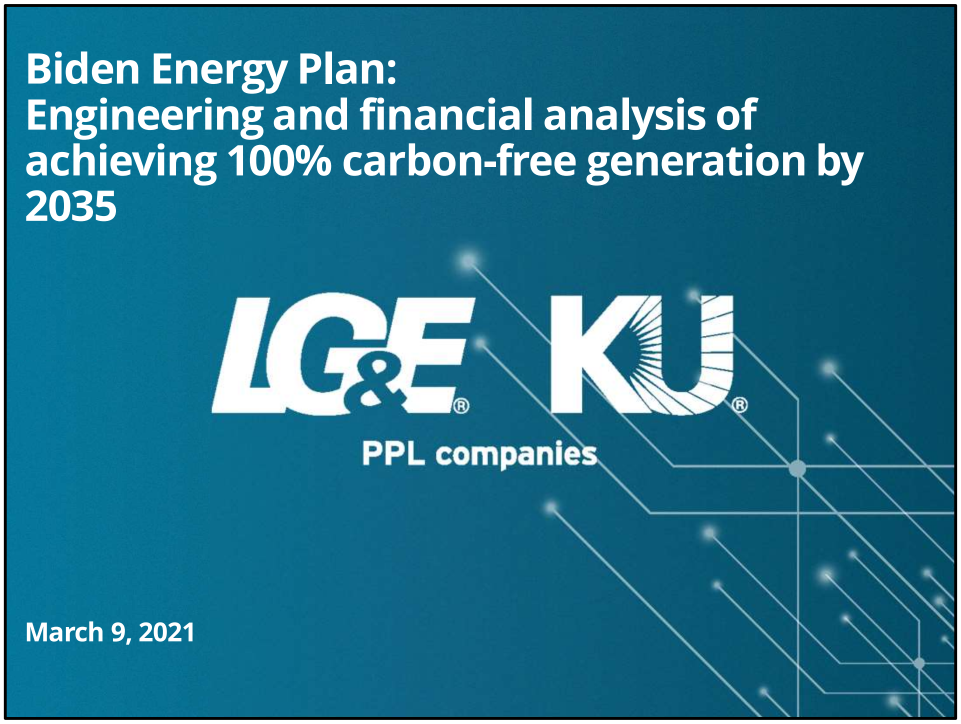
**Question No. 2.52**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.52. Considering the Biden Administration and the nation's focus on rapidly reducing greenhouse gas emissions in response the climate crisis, which the Company has acknowledged in the IRP (p. 13, Vol. III); and Louisville Metro Government's commitment to reaching 100% clean energy for Metro operations by 2030 and the entire community by 2035; and PPL's climate commitments, have the Companies evaluated a range of scenarios based on achieving aggressive emission reduction goals? For example, achieving a 50% reduction in CO2 emissions by 2030 and 100% reduction by 2036?

If yes, please provide all data, analysis, and workpapers associated with these scenarios.

A-2.52. See attached.




- Analysis is based on engineering data and actual load, solar, and wind characteristics.
- This information is intended to drive discussion and is not a plan or recommended course of action.

## Key attributes of the Biden Energy Plan

- 100% carbon free power by 2035
- Increased energy efficiency standards
  - Retrofit 4 million buildings and 2 million households with more energy efficient appliances
  - Net-zero emissions for all new buildings by 2030
- Promote EV deployment via tax incentives, rebates for IC trade-ins, and 500,000 new public charging stations across the U.S.
  - Transition 3 million government vehicles to zero-emission vehicles
  - All new public transport buses are zero emission by 2030
  - Convert all school buses to zero emission within five years
- Install 500 million solar panels and 60,000 made-in-America wind turbines within five years, including eight million solar roofs and community solar energy systems
- "Buy Clean and Buy America" standards to incentivize production of low-carbon building and construction materials, like steel and cement, here in the United States

## Many claim that carbon-free electricity is reliable and economic

- Rocky Mountain Institute – Clean Energy Portfolio is likely more cost-effective than running existing gas plant by the early 2030s
- Energy Innovation & Vibrant Clean Energy – coal plants can be replaced by clean energy with lower costs
- Mark Jacobson, Stanford and The Solutions Project – 100% renewable by 2035
- National Academies of Sciences, Engineering, Medicine – Deep decarbonization by 2050 is technically feasible and spending will be manageable
  - 75% non-carbon-emitting target for electricity by 2030
- Goldman School of Public Policy, UC Berkeley – 90% carbon-free electricity by 2035
- Various studies from universities, NGOs, and think tanks

## UC Berkeley – 90% carbon-free electricity is technically and economically achievable by 2035

- Key Assumptions
  - All coal plants are retired
  - No new gas plants are built
  - Retain 2/3 of existing gas capacity
  - Existing hydro and nuclear are retained (except announced retirements)
- New generation installed by 2035 would equal existing total capacity
  - 575 GW of new wind (104 GW installed as of 2019)
  - 525 GW of new solar (61 GW installed as of 2019)
  - 100 GW of battery storage (2 GW installed as of 2020)
  - Existing US capacity is around 1,000 GW
- 90% Clean being "more economic" than alternative depends on:
  - $1.2 trillion in health benefits through 2050 - $20/MWH
  - Limited investment in new transmission (renewables & storage are built locally)
  - Unrealistic "No New Policies" case that grows coal energy generation while reducing gas compared to present (drives health benefits of 90% Clean case)

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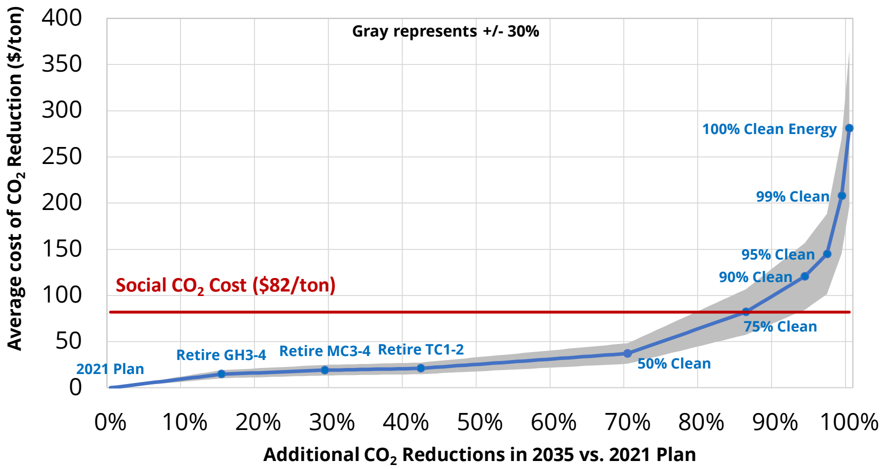
- Note that 100 GW of installed battery capacity is consistent with 2030 goal of U.S. Energy Storage Association.
- Assumption that limited transmission investment is required at odds with most other studies that support high concentration of renewables.

## 2021 BP reduces $CO_2$ by 23% from 2020 but accelerating coal retirements and reducing NG would drive up cost of additional reductions

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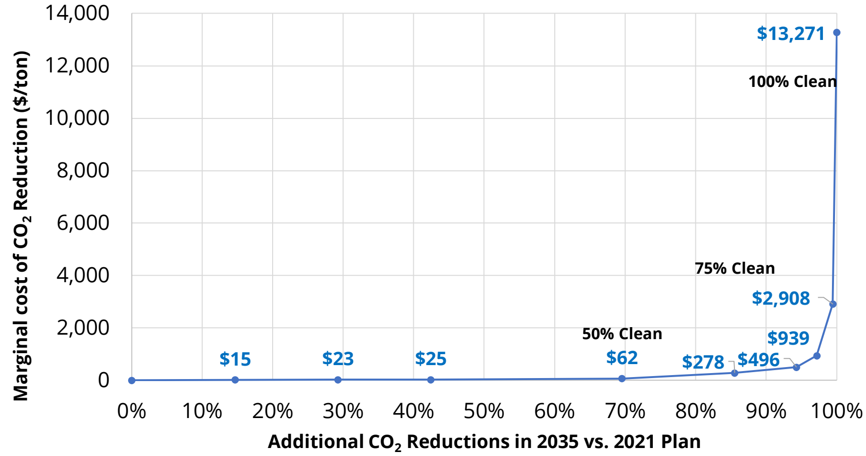
- All CO2 volumes were calculated in short tons.
- Natural gas is important to keeping our cost of CO2 reductions affordable.
- According to 2021 BP – CO2 emissions will decline from 30 million tons in 2020 to 23 million tons in 2035. Reductions prior to 2035 are due to retiring coal and building NGCC. It can be argued that the cost of these CO2 reductions is negative since economics are driver for retiring these units – not CO2 emission reductions.
- Per recent solar contract price, about 1 million tons could be reduced for between negative $5 / ton (assuming REC sales ) to positive $5 per ton with no REC sales (compared to marginal cost of coal).
- All coal plants are assumed to be replaced with NG NGCC.
- 50% clean cases and above assume post-2035 coal plants are only replaced with renewables and storage (i.e., only pre-2035 NGCCs are built).
- Social cost of carbon in 2035 is $67 / metric ton in $2020 per recent Biden Admin. change. Converting to short tons and escalating at 2% yields $82 / short ton.

## Marginal $CO_2$ reductions from 21 BP beyond 75% (50% Clean) are more expensive than social cost of carbon in 2035

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- Marginal cost of CO2 reductions calculated from "middle" of average CO2 costs from prior slide.

# Problem to be solved: Reliably serving load at lowest reasonable cost

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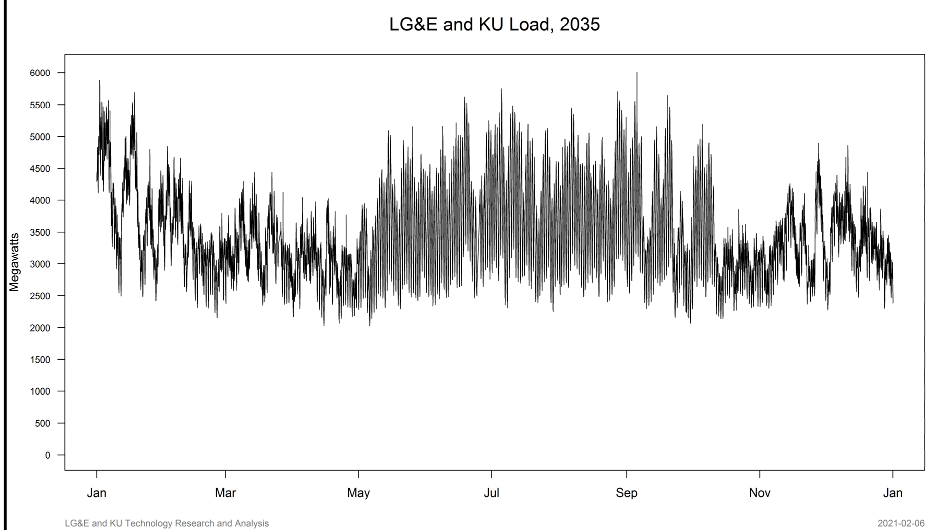
# LG&E and KU load peaks in winter and summer

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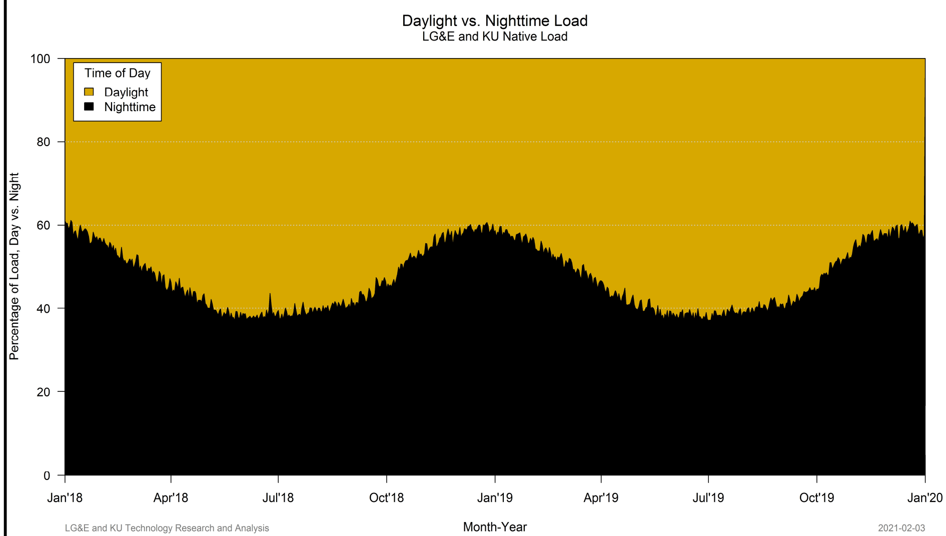
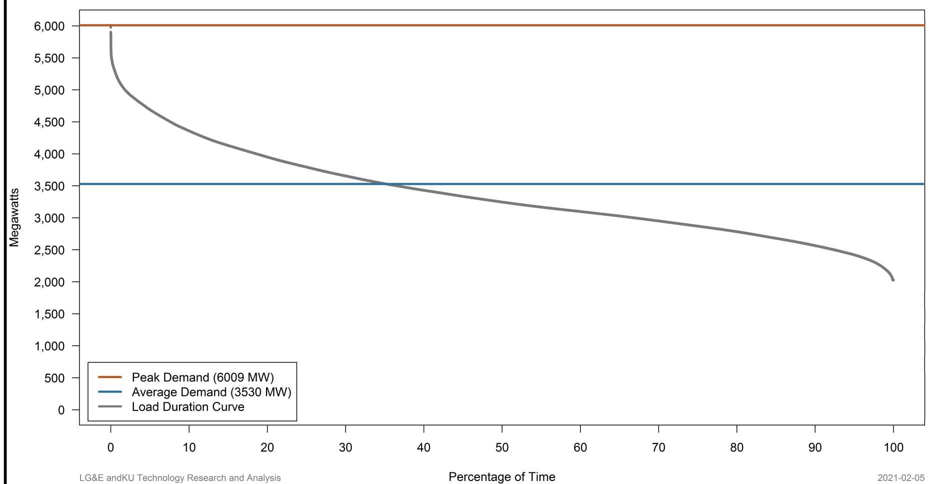
1-minute load

## 60% of LG&E and KU winter demand occurs at night



# 2035 Load Duration Curve

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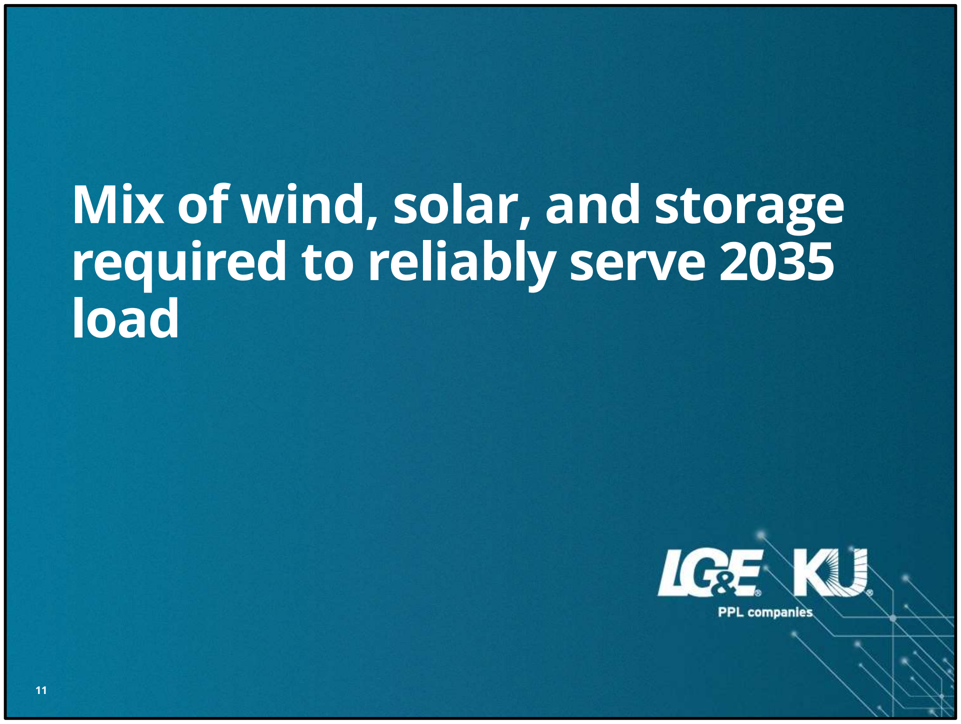
Mix of wind, solar, and storage required to reliably serve 2035 load
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## Viable carbon-free technologies are limited today

- Existing carbon-free technologies are solar, wind, and lithium-ion batteries
- Nuclear is assumed not to be an option by 2035 given development lead time and likely resistance to new greenfield sites
- Current price of "green" hydrogen ($H_2$) is around $80 / MMBtu and supply is limited so not used in first phase
- Rush to build existing carbon-free generation would likely drive costs higher than in status quo
  - Analysis assumes carbon-free technology costs stay at today's levels
- Assumed that all future generation is self-build
- No incremental cost for new transmission infrastructure included but material investments would be required due to reliance on inverter technology (see "Transmission Considerations" appendix)

# 2035 generation resource cost assumptions for Biden Energy Plan analysis

| | Solar | Kentucky Wind | Battery Storage* | Hydrogen Combined Cycle |
|---|---|---|---|---|
| Capital Cost ($/kW) | $1,042 | $1,753 | $1,075 | $1,055 |
| Fixed O&M ($/kW-yr) | $6.24 | $34.55 | $17.83 | $73 |
| Variable Cost ($/MWh) | $0 | $0 | $0 | $105 |
| Capacity Factor | 24.7% | 24.6% | -- | 85% |

* 1 MW and 4 MWh lithium-ion energy storage system.
Solar, wind, and storage are higher than otherwise would be the case given increase in demand nationwide.
Hydrogen CCGT costs same as projected for NG unit.
Distributed solar was not evaluated given its higher installed cost and lower capacity factor compared to utility scale.
KY wind used because out of state sites assumed to be utilized to meet wind needs in those states and avoid the need to build large-scale interstate transmission by 2035.



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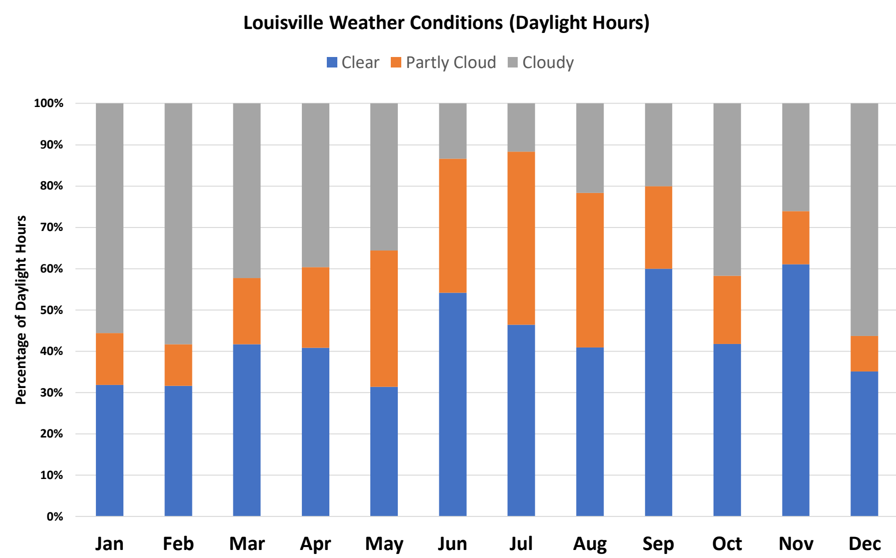
## Resources required to serve load were determined by utilizing real-world data

- All load, solar, and wind data based on actual 1-minute data from 2018
- 2035 load forecast was allocated to 2018 1-minute pattern
- Solar generation based on actual data from 67 sites across KY
- Wind generation based on actual data from best KY site
- Thousands of generation portfolios were evaluated to identify lowest-cost options
- No load uncertainty, reserve margin, or contingency/operating reserves were assumed

## The sky is usually cloudy in the winter

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- Clouds greatly impact size of solar and battery storage.

# Serving load with renewables and battery storage would require $74 billion investment

| | 2021 BP | | Biden Scenario | |
|---|---|---|---|---|
| | Capacity (MW) | Energy (TWh) | Capacity (MW) | Energy (TWh) |
| 2035 Peak Demand/Energy Requirements | 6,009 | 31 | 6,009 | 31 |
| Coal | 2,900 | 15 | -- | -- |
| Gas | 4,076 | 16 | -- | -- |
| Solar | 10 | 0 | 18,000 | 39 |
| Wind | -- | -- | 9,000 | 19 |
| Storage used to serve load | -- | -- | 23,000 | 10 |
| Unused solar/wind | -- | -- | | 23 |
| Inverter and battery losses | | | | 4 |
| | | | | |
| Total fuel costs ($B) | 0.8 | | 0 | |
| New investment by 2035 ($B) | 2 | | 74 | |

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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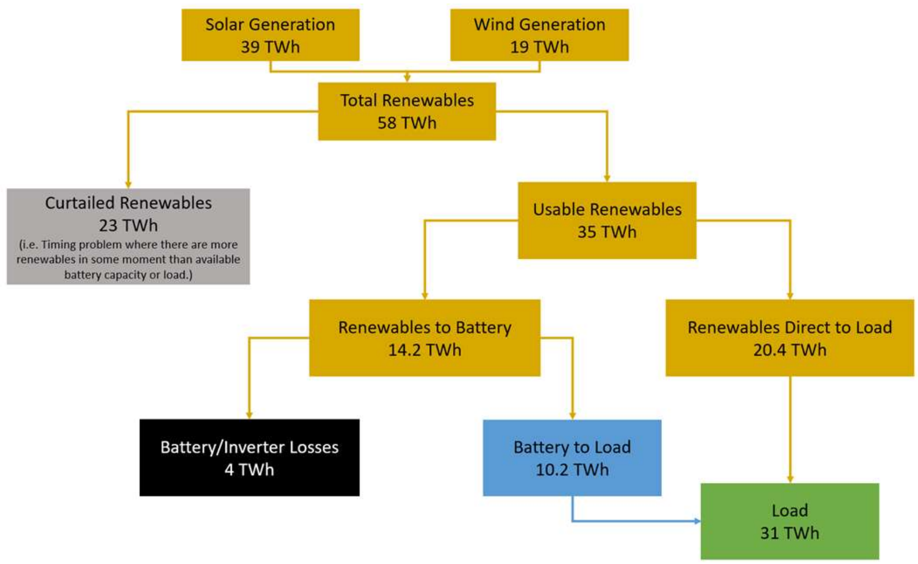
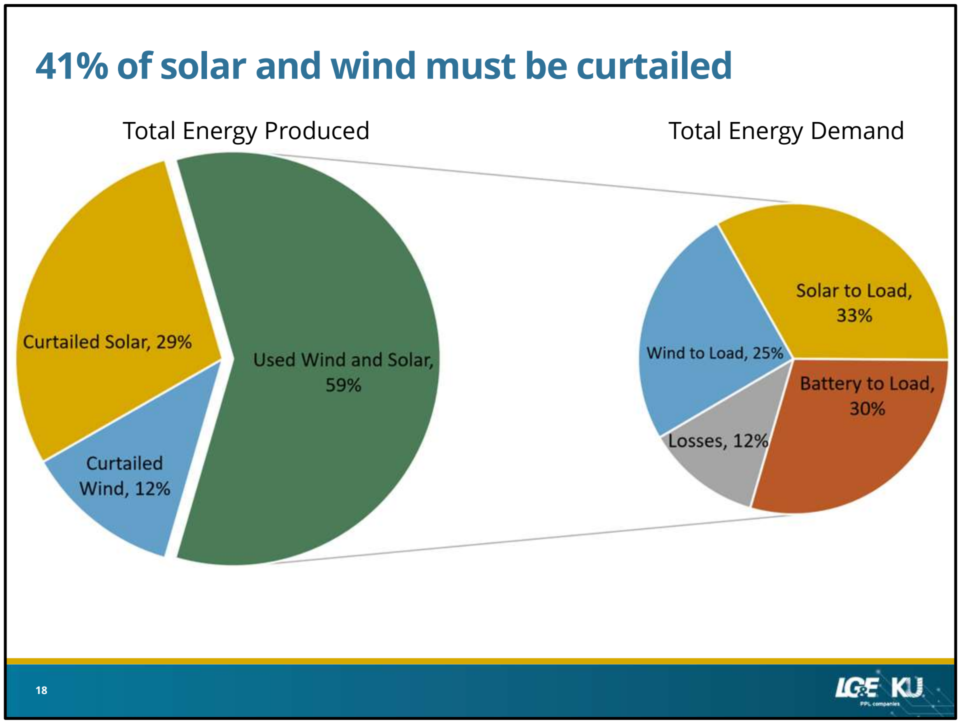
See next slide for details on sources and sinks for generation.

## Energy by Source and Sink




41% of solar and wind must be curtailed
Total Energy Produced
Total Energy Demand
Curtailed Solar, 29%
Used Wind and Solar, 59%
Curtailed Wind, 12%
Solar to Load, 33%
Wind to Load, 25%
Battery to Load, 30%
Losses, 12%
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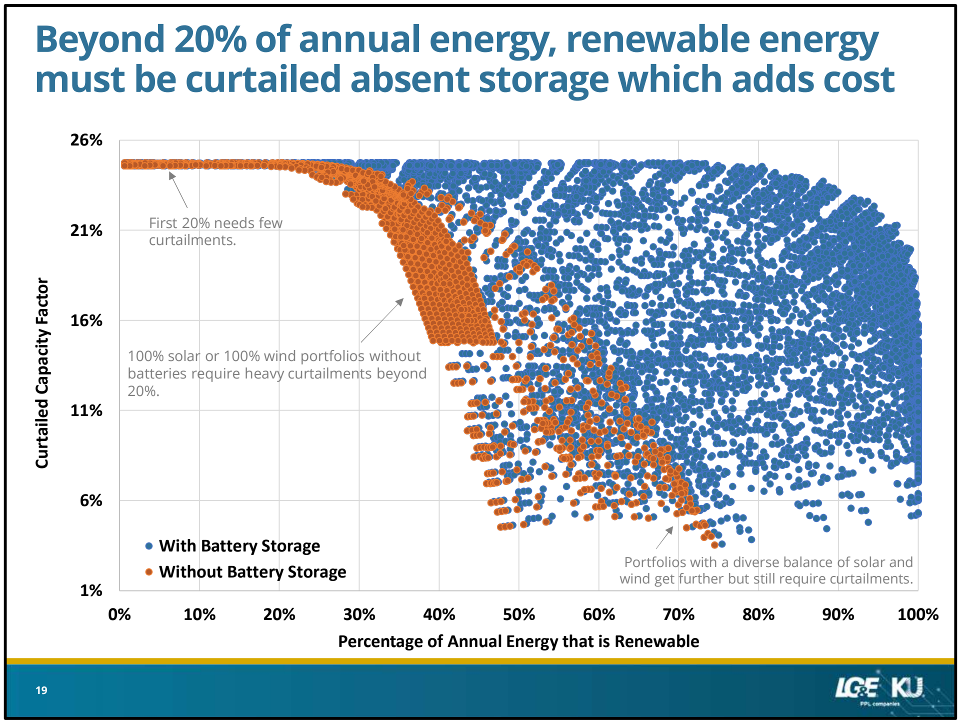
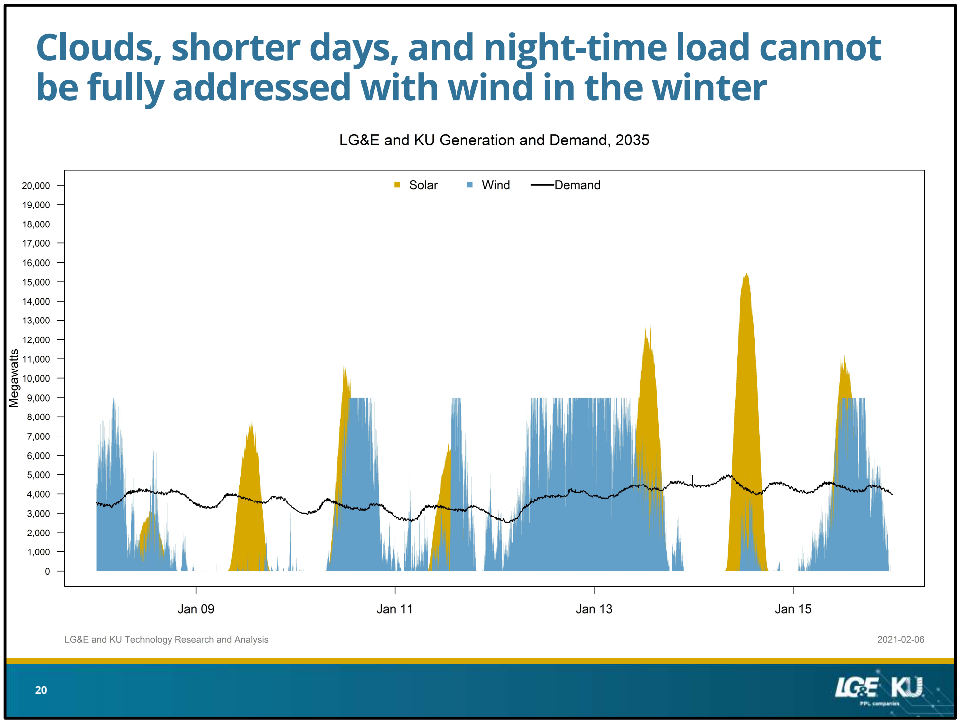
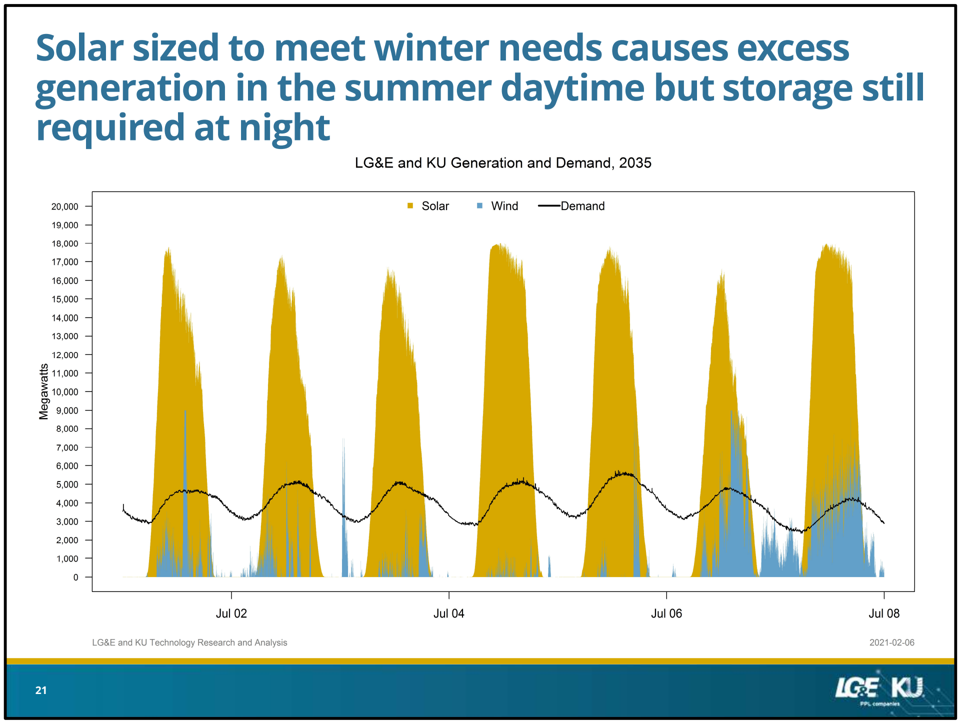



- Dots represent various alternative combinations of wind, solar, and storage that the model evaluated.
- Best performing portfolios are along the top part of the chart. Hence, adding storage begins to make sense when annual renewable energy reaches 20 -30 percent of annual energy.
- However, adding storage just adds to overall costs - building electron warehouses in order to move energy around in time and energy losses associated with round-trip storage.
- Results are consistent with CA's actual experience at around 25 percent annual renewables with energy dumping to AZ, adding storage, and curtailing renewables.

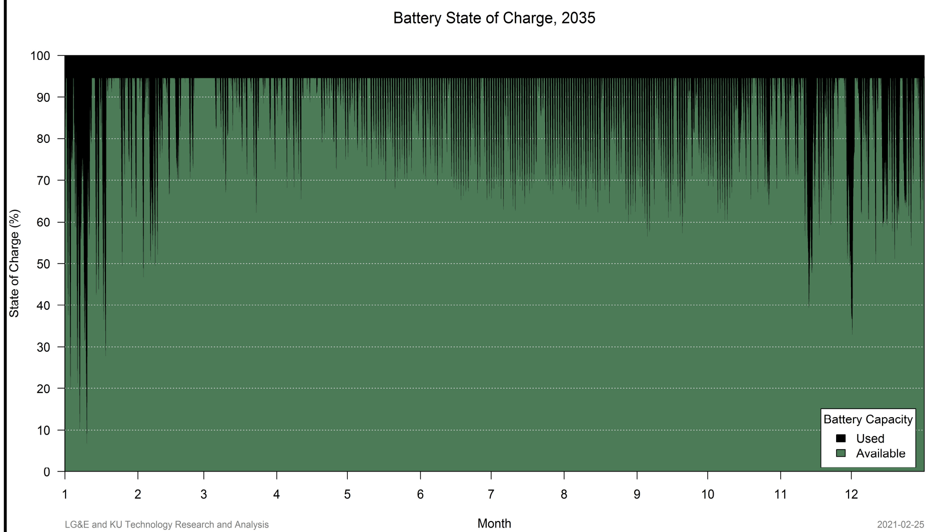



- "White" area below the load curve would be unserved energy absent being served by storage.
- Generation above load would be used to charge batteries assuming capacity and energy volume is available. If not, generation would need to be curtailed.




- "White" area below the load curve would be unserved energy absent being served by storage.
- Generation above load would be used to charge batteries assuming capacity and energy volume is available. If not, generation would need to be curtailed.

# Battery sized to meet cold, dark winter weeks while in summer they cycle daily

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- Even if only needed for a brief period, battery must be sized to address load.
- Battery size is driven by i) limited window of time to charge due to availability of excess solar/wind and ii) duration of energy required to serve load (e.g., night) when solar/wind is not able to meet load.

## Conclusion: Existing renewable technology is expensive to reliably serve 100% of load

- Serving winter load is challenged by clouds, less daylight, and high load for heating
- Cost is much higher than what zero $CO_2$ proponents believe
  - $74 billion investment vs. $2 billion in 2021 BP
  - Annual fixed charge of capital costs are likely 10x greater than fuel savings
- Such a huge increase in energy costs would have dramatic impacts on economy, jobs, and load

## Breakthroughs in Green $H_2$ prices would lower costs and require fewer renewables and no battery storage

- Evaluated $H_2$ improvements to reduce cost
  - Green $H_2$ is assumed to be priced in 2035 at today's price of Grey $H_2$ of \$10 to \$22 /MMBtu (used \$16.48 / MMBtu in the analysis)
  - Future $H_2$-burning turbines and infrastructure assumed to cost the same as today's NG-based system

## With favorable $H_2$ assumptions, required investment is 6x 2021 BP but fuel costs also increase by 3-fold

| | 2021 BP | | Existing Technology | | Add Hydrogen | |
|---|---|---|---|---|---|---|
| | Capacity (MW) | Energy (TWh) | Capacity (MW) | Energy (TWh) | Capacity (MW) | Energy (TWh) |
| 2035 Peak Demand/Energy Requirements | 6,009 | 31 | 6,009 | 31 | 6,009 | 31 |
| Coal | 2,900 | 15 | -- | -- | -- | -- |
| Gas | 4,076 | 16 | -- | -- | -- | -- |
| Solar | 10 | 0 | 18,000 | 39 | 4,500 | 10 |
| Wind | -- | -- | 9,000 | 19 | 90 | 0.2 |
| Storage | -- | -- | 23,000 | 10 | 0 | 0 |
| Hydrogen | -- | -- | | | 6,000 | 21 |
| Unused solar/wind | -- | -- | | 23 | | 0.5 |
| Inverter and battery losses | | | | 4 | | 0 |
| | | | | | | |
| Total fuel costs ($B) | 0.8 | | 0 | | 2.5 | |
| New investment by 2035 ($B) | 2 | | 74 | | 13 | |

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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- H2 capacity and dispatchability eliminates the need for battery storage.
- Solar and wind are added to avoid high energy cost of using H2 (over $100/MWh).
- Note that solar/wind make up about 1/3 of total load so annual energy limit is reached consistent with slide #19. This minimizes unused solar/wind and eliminates the need for storage.

# Reducing clean energy targets would lower overall costs but would still be expensive

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## Getting to 50% Clean by 2035 will still be expensive and getting the last 10% more than doubles required investment compared to 90% Clean

| | 2021 BP | | 50% Clean | | 75% Clean | | 90% Clean | | 100% Clean | |
|---|---|---|---|---|---|---|---|---|---|---|
| **$CO_2$ Emissions (millions of short Tons)** | 22.6 | | 6.5 | | 3.1 | | 1.3 | | 0 | |
| | **MW** | **TWh** | **MW** | **TWh** | **MW** | **TWh** | **MW** | **TWh** | **MW** | **TWh** |
| **Load** | 6,009 | 31 | 6,009 | 31 | 6,009 | 31 | 6,009 | 31 | 6,009 | 31 |
| **Coal** | 2,900 | 15 | -- | -- | -- | -- | -- | -- | 0 | 0 |
| **Gas** | 4,076 | 16 | 4,300 | 15 | 3,700 | 8 | 3,300 | 3 | 0 | 0 |
| **Solar** | 10 | 0 | 7,200 | 15 | 9,300 | 20 | 13,100 | 28 | 18,000 | 39 |
| **Wind** | -- | -- | 700 | 2 | 3,800 | 8 | 4,300 | 10 | 9,000 | 19 |
| **Hydro** | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 |
| **Battery Storage** | -- | -- | 3,400 | 8 | 6,100 | 10 | 10,700 | 12 | 23,000 | 10 |
| **Unused Solar/Wind** | -- | -- | -- | 11 | -- | 2 | -- | 6 | -- | 23 |
| **Battery/Inverter Losses** | -- | -- | -- | 6 | -- | 4 | -- | 4 | -- | 4 |
| | | | | | | | | | | |
| **Fuel costs ($B)** | 0.8 | | 0.4 | | 0.2 | | 0.1 | | 0 | |
| **New investment by 2035 ($B)** | 2 | | 12 | | 23 | | 33 | | 74 | |

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.



- New Investment in "Clean" scenarios is incremental to 2021 BP.
- Large increase in cost to go from 90% Clean to 100% Clean was the reason the Berkeley study stopped at 90%. We are told by someone involved with the study that the original intent was to get to 100% Clean.

# Alternative technology and markets

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## Rapid breakthrough in technologies is required very soon to achieve mass adoption by 2035

- $H_2$ – LCRI is focused on at least a decade of research
  - Green H2 would require massive renewable buildout as well because high-capacity factor for electrolyzer drives economics
  - Broad commercial application not consistent with 2035 goal
    - McKinsey & Co. estimate 14% of power generation from $H_2$ by 2050
- CCS – Despite research, economic and legal (sequestration) challenges remain large
  - Elon Musk offered $100 million prize for best project
  - Not likely to be applied to existing coal units
- Nuclear
  - Large scale – 4 licenses (FPL, DUK, DOM, DTE) approved for 6 units
  - Small Module – lots of research and interest worldwide but not much progress on large scale commercial deployment
    - License process not materially different from large scale reactors

## Joining an RTO would expand geography but does not fundamentally alter technology challenges

- Weather impacts on load are correlated
- Solar challenges remain
  - Day/night limitations not materially altered
  - Winter clouds are problematic throughout the Midwest and East
- Best wind sites would likely be needed to serve existing RTO load
- Battery storage supports the grid best near load (see "Transmission Considerations" appendix)
- Significant transmission would need to be built if new generation is not located in proximity to existing generation


Conclusions
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## Biden Energy Plan goal of carbon-free electricity by 2035 is extremely aggressive

- Achieving carbon-free electricity by 2035 with today's technology seems unlikely and would be wildly expensive
- Assuming breakthrough in Green $H_2$ production would reduce costs dramatically but such a development is highly speculative
  - $H_2$ generation eliminates the need for battery storage but maybe not for $H_2$ production to achieve high capacity factor for production
  - Renewables still deployed to reduce high $H_2$ generation fuel costs
- Other zero carbon technologies not likely to be commercially deployed on a broad scale on the necessary timeline
- A rapid transition to carbon-free electricity by 2035 would likely be extremely disruptive to the economy and have a large, negative impact on jobs and load



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# Appendix: Transmission Considerations

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# Transmission Provides Operating Reliability

- Transmission's role is to plan, construct, and maintain reliable operation of the LG&E and KU transmission system while accommodating new generation, generation retirements, and serving firm load and firm transmission service obligations.
- Planning the transmission system is achieved primarily thru completion of Steady State and Dynamic Stability Analysis and relies heavily on forecasts provided by generators and load serving entities.
  - *Steady State Analysis:* *Identifies overloads and voltage violations on the Transmission System once it has reached a state of equilibrium.*
  - *Stability Analysis:* *Identifies issues with voltage and frequency on the Transmission System immediately after a fault is cleared.*
  - *Violations identified through analysis can be resolved by system operating instructions, additions and/or upgrades to primary equipment (lines, power transformers and substn equipment, capacitors, etc.).*



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# Transmission Summary – Biden Energy Plan

- Transmission requirements to convert existing spinning and conventional generation to inverter-based generation (i.e., solar, wind, and batteries) are known and manageable.
- **Location** of new inverter-based generation, and subsequent retirement of existing generation, is a key factor in planning and constructing the transmission system for reliable operations.
- The significant generation turnover and pace of change would present many challenges.
  - Accurate forecasts of future generation, generation retirements, and load will be critical for a successful transition.
  - As part of the eastern interconnection, similar transitions from neighboring transmission system will require significant coordination and potentially other transmission upgrades.
  - Timing to complete major upgrades (e.g., siting, permitting, and construction of new high voltage lines) are uncertain.
- An accurate cost estimate range is impossible without further details, including location of new generation.



2300 MVARs is the reactive capacity of LG&E/KU existing fleet

## How Would Transmission Planning Support the Transition to Inverter-Based Resources?

- Build additional off-peak models to analyze solar and wind generation and charging of batteries.
- Perform Steady State Analysis
  - Identify new transmission equipment required to accommodate inverter-based generation and retire existing generation.
  - Identify and mitigate voltage issues and thermal overloads of existing transmission equipment.
  - While analyzing our transmission system, identify voltage issues and thermal overloads on neighboring transmission systems.
- Perform Dynamic Stability Analysis
  - Identify and mitigate issues related to voltage, frequency, rotor angle, and transient stability.

## Equipment Required for New Generation & Thermal Overload Mitigation

- New interconnection facilities and network upgrades will be required to accommodate 18GW of solar and 9GW of wind generation. Network upgrades and costs would be minimized if located at our near existing generation facilities or major substations.
- Location of the significant amount of required storage (23GW) will likely require major network upgrades, even if dispersed geographically across the state.
- Additional high voltage interconnections with neighboring transmission systems will be considered to add system support.

# Maintaining Voltage Support

- Inverter-based resources can provide voltage support but at the expense of reducing real power.
  - There are no existing requirements to oversize inverters (capacity margin) to provide necessary voltage support.
- Additional support or a more economical solution may be to install voltage supporting equipment. This type of equipment is typically considered "primary", located in a substation, and can be large and costly (see below).
  - Examples of such primary equipment might be capacitors and static var compensators
- Resources and/or additional voltage support equipment installed at or near existing generation plants or substations may provide support at the lowest cost by locating near existing transmission capacity.



2300 MVARs is the reactive capacity of LG&E/KU existing fleet

## Maintaining Frequency Control

- Inverter-based resources can provide frequency support. Appropriate real power must be held in reserve in case needed to support a low frequency system event. Real power must be reduced to assist in a high frequency system event.
  - There are no existing requirements to oversize inverters (capacity margin) to provide necessary frequency support.
- Additional support or a more economical solution may be to install frequency supporting equipment. A synchronous condenser could provide some frequency support in addition to voltage support.
  - Similar to primary equipment used to support voltage, synchronous condenser are large and costly.
- Resources and/or additional frequency support equipment installed at or near existing generation plants or substations may provide sufficient support at the lowest cost by locating near existing transmission capacity.

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HVDC lines are only cost effective if power is transported at least 400-500 miles. Therefore, not a good option for Kentucky.

## Open Access Transmission Tariff (OATT) Services Should be Considered

- Evaluation of existing ancillary services provided to third party transmission customers will need to be considered.
  - LG&E and KU are obligated to offer ancillary services via the OATT
  - Approximately 600 MWs of third party peak load currently subscribe for voltage control, frequency response, operating reserves, and imbalance services.
  - OATT ancillary services purchased and offered to others should be considered when making final resource decisions.

## Estimated transmission expense is relatively small compared to generation costs.

- As noted, the location of future inverter-based resources will drive the necessary transmission upgrades and cost.
- Evaluation of the location should consider transmission costs to determine the least cost option.
- It is difficult to estimate transmission expense without a more detailed breakdown of future capacity and location. However, transmission costs are typically a relatively small percentage of generation costs.
  - *For example, at an estimated cost of $74 billion for the inverter-based resources, a $7.4 billion transmission cost estimate would equate to 10% of the generation cost.*
  - *By comparison, the current rate base of the entire LG&E and KU transmission system is approximately $850 million.*
- One approach could be to develop estimates in a phased approach using the current generator interconnection queue. Even order-of-magnitude estimates would require significant resources and time to accomplish.

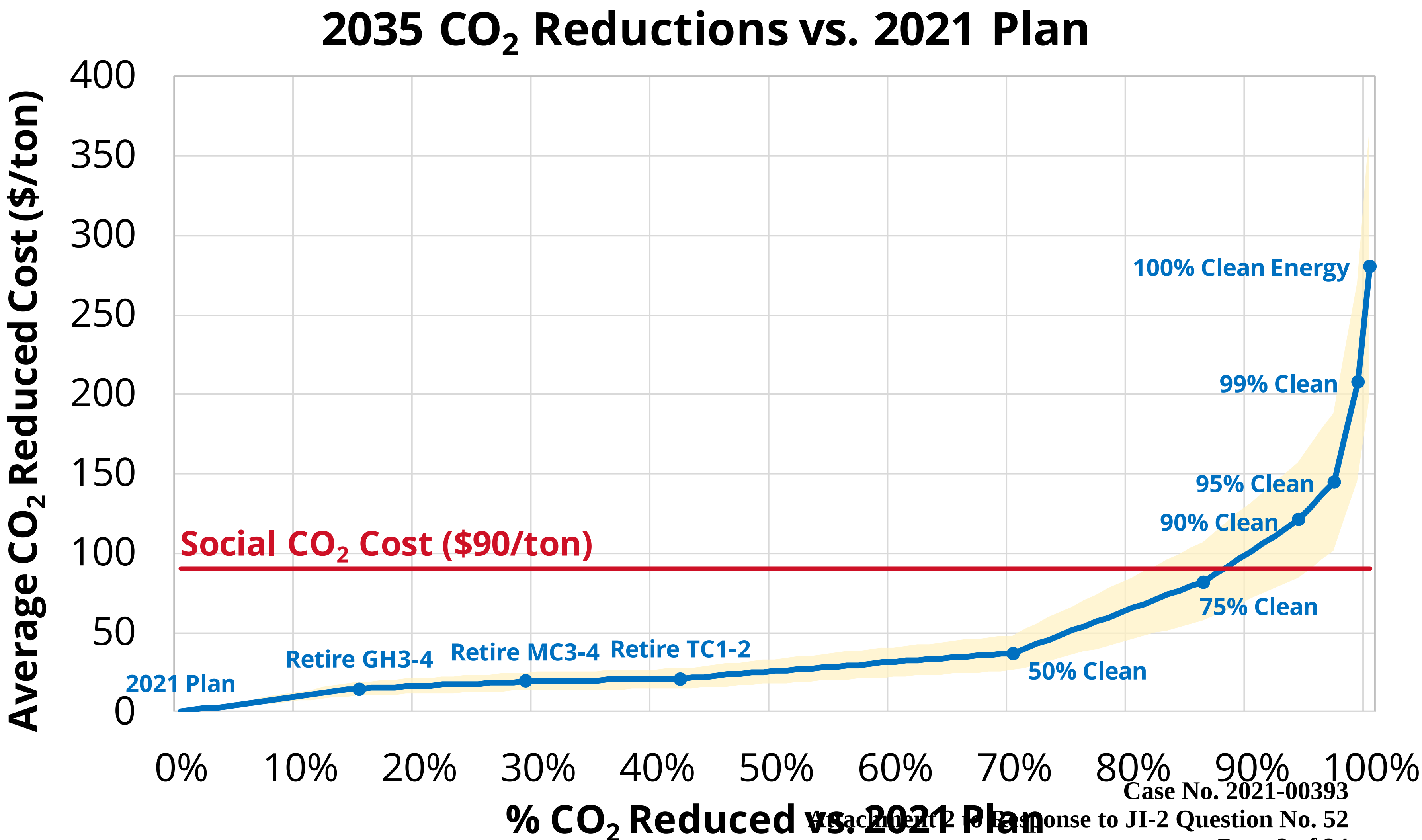


LG&E KU
PPL companies

# Backup Data for Biden Energy Plan Evaluation

February 2021
Energy Planning, Analysis, and Forecasting
Technology Research and Analysis

# Carbon dioxide emissions reductions are increasingly expensive with scale.

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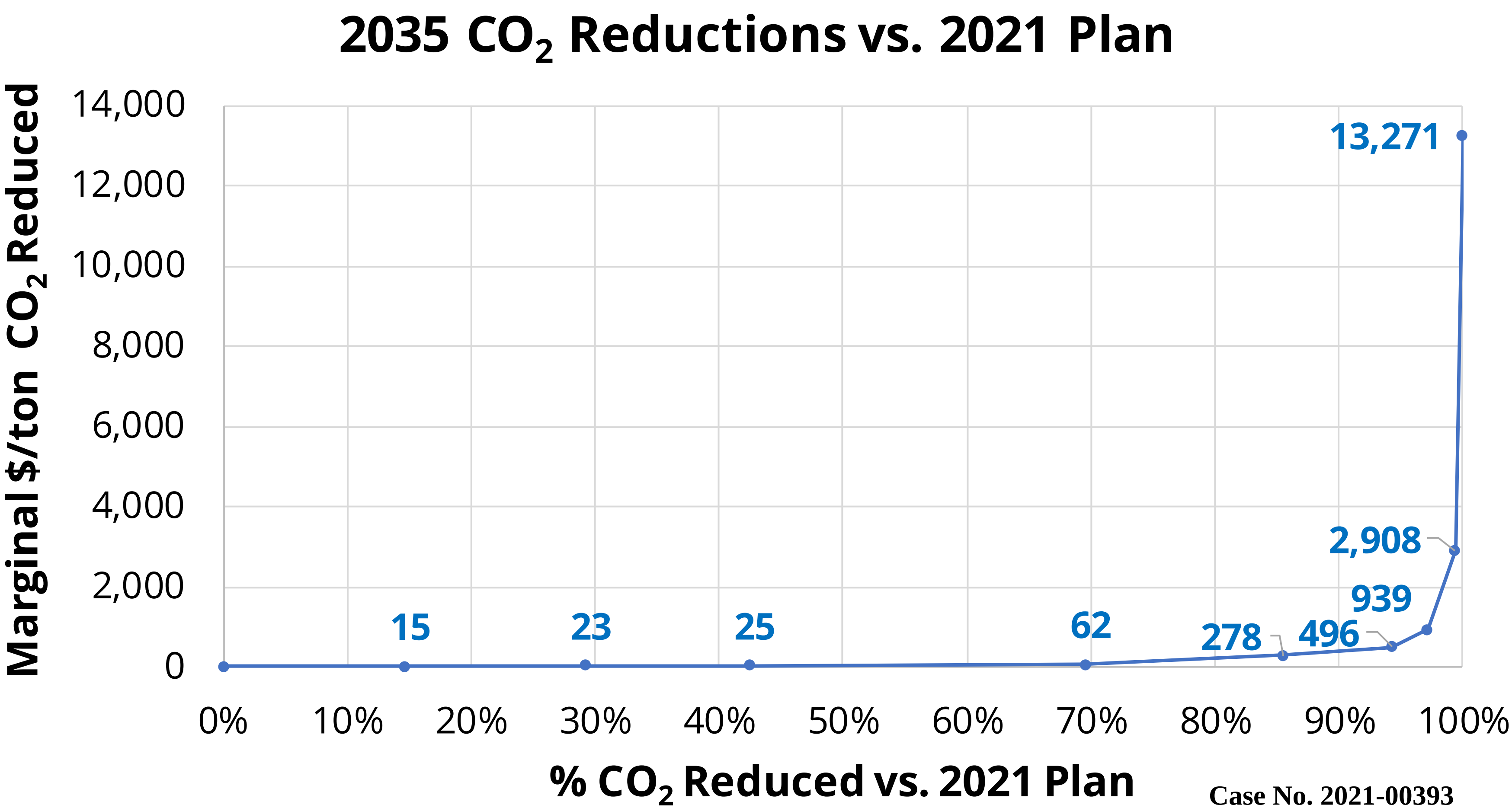
# The marginal costs of reducing incremental CO2 are markedly more expensive

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LG&E KU
PPL companies

# Serving load with 100% renewables will require more than $74b investment.

| | 2021 BP | | 50% Clean | | 75% Clean | | 90% Clean | | 100% Clean | |
|---|---|---|---|---|---|---|---|---|---|---|
| $CO_2$ Emissions (Short Tons) | 22.6 | | 6.5 | | 3.1 | | 1.3 | | 0 | |
| | MW | TWh | MW | TWh | MW | TWh | MW | TWh | MW | TWh |
| **Load** | 6,009 | 31 | 6,009 | 31.0 | 6,009 | 31.0 | 6,009 | 31.0 | 6,009 | 31 |
| **Coal** | 2,900 | 15 | -- | -- | -- | -- | -- | -- | 0 | 0 |
| **Gas** | 4,076 | 16 | 4,300 | 15.4 | 3,700 | 7.7 | 3,300 | 3.1 | 0 | 0 |
| **Solar** | 10 | 0 | 7,200 | 15.4 | 9,300 | 19.9 | 13,100 | 28.0 | 18,000 | 39 |
| **Wind** | -- | -- | 700 | 1.5 | 3,800 | 8.4 | 4,300 | 9.5 | 9,000 | 19 |
| **Hydro** | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 | 134 | 0.3 |
| **Battery Storage** | -- | -- | 3,400 | 7.8 | 6,100 | 9.7 | 10,700 | 11.5 | 23,000 | 10 |
| **Unused Solar/Wind** | -- | -- | -- | 10.7 | -- | 1.8 | -- | 5.7 | -- | 24 |
| **Battery/Inverter Losses** | -- | -- | -- | 5.6 | -- | 3.6 | -- | 4.3 | -- | 2 |
| | | | | | | | | | | |
| **Fuel costs ($B)** | 0.80 | | 0.40 | | 0.19 | | 0.08 | | 0.00 | |
| **New investment by 2035 ($B)** | 2 | | 12 | | 23 | | 33 | | 74 | |

*Existing hydro units remain in service in all scenarios.

**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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# Serving load with 100% renewables will require more than $74b investment.

| | 50% Clean | 75% Clean | 90% Clean | 100% Clean |
|---|---|---|---|---|
| **Gas (GW)** | 4↔5 | 3↔5 | 1↔5 | 0↔0 |
| **Solar (GW)** | 1↔19 | 1↔20 | 3↔20 | 5↔30 |
| **Wind (GW)** | 0.5↔10 | 1↔10 | 1↔20 | 5↔20 |
| **Battery Storage (GW)** | 3↔8 | 5↔18 | 9↔25 | 14↔33 |
| **CO2 Emissions (M Short Tons/Year)** | 4↔7 | 2↔5 | 0.6↔3 | 0↔0 |
| **New investment by 2035 ($B)** | 12↔40 | 19↔115 | 27↔135 | 74↔164 |

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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# Load Profile

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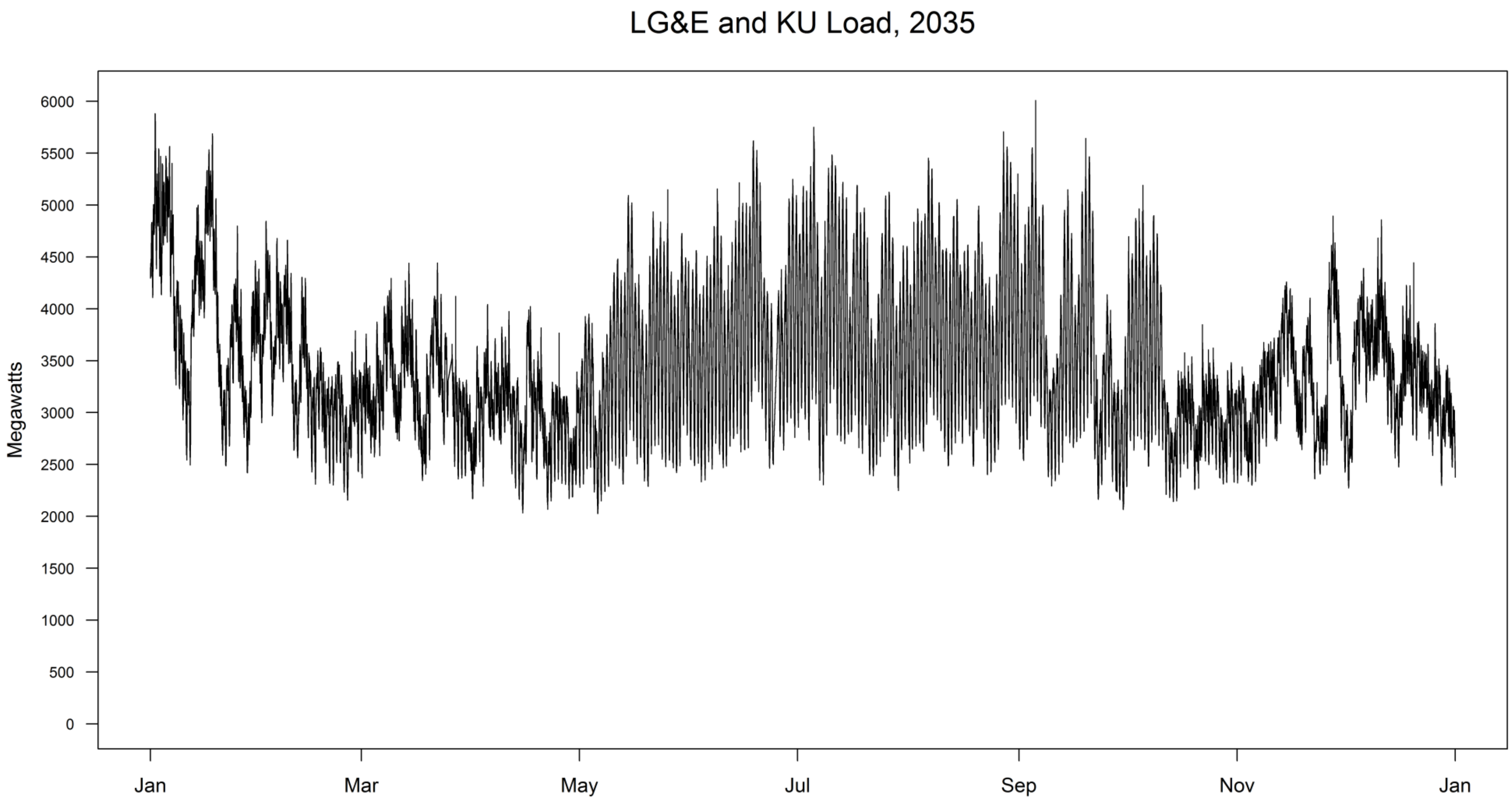
# LG&E and KU load peaks in winter and summer

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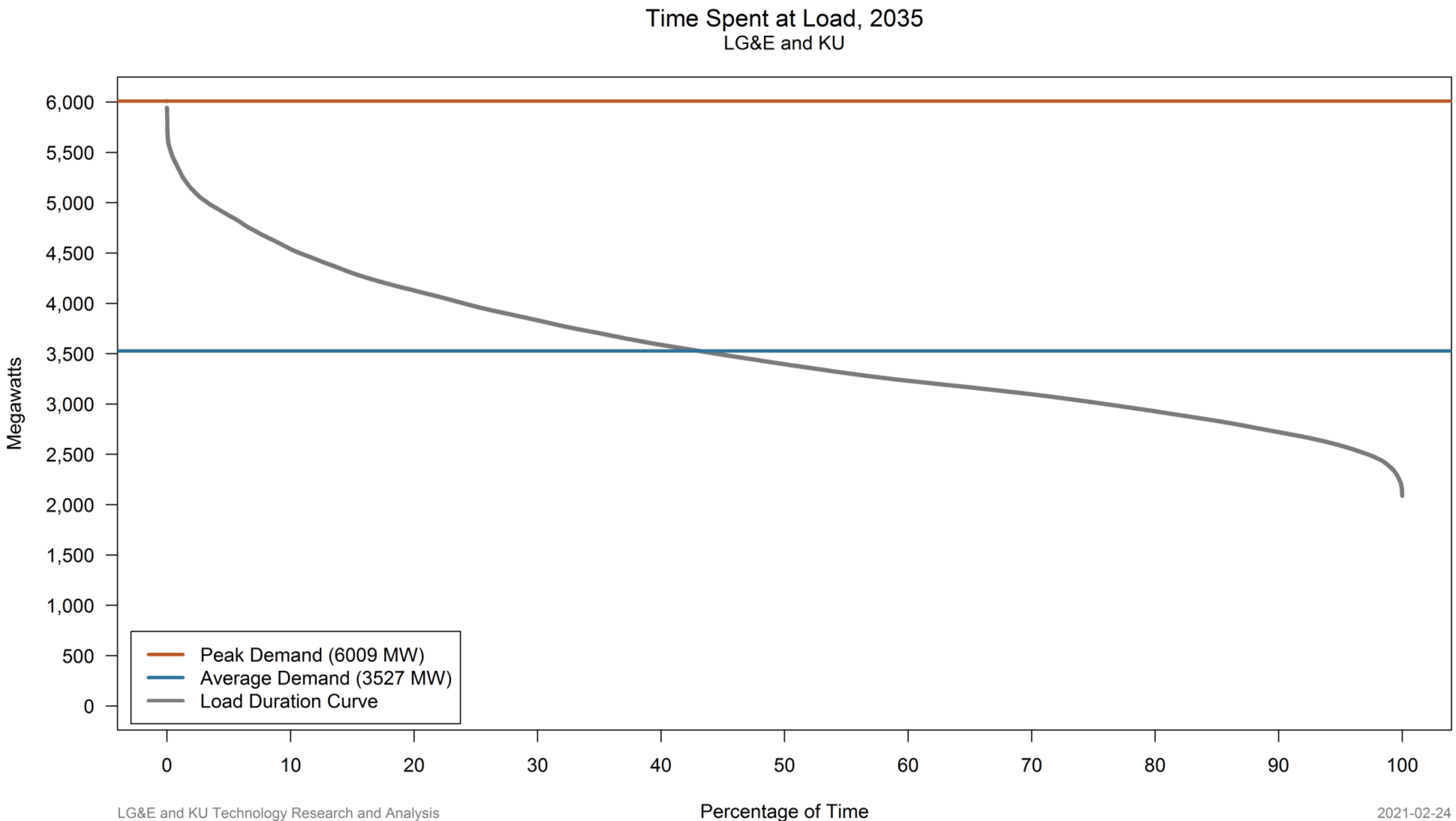
PPL companies

# 2035 Load Duration Curve

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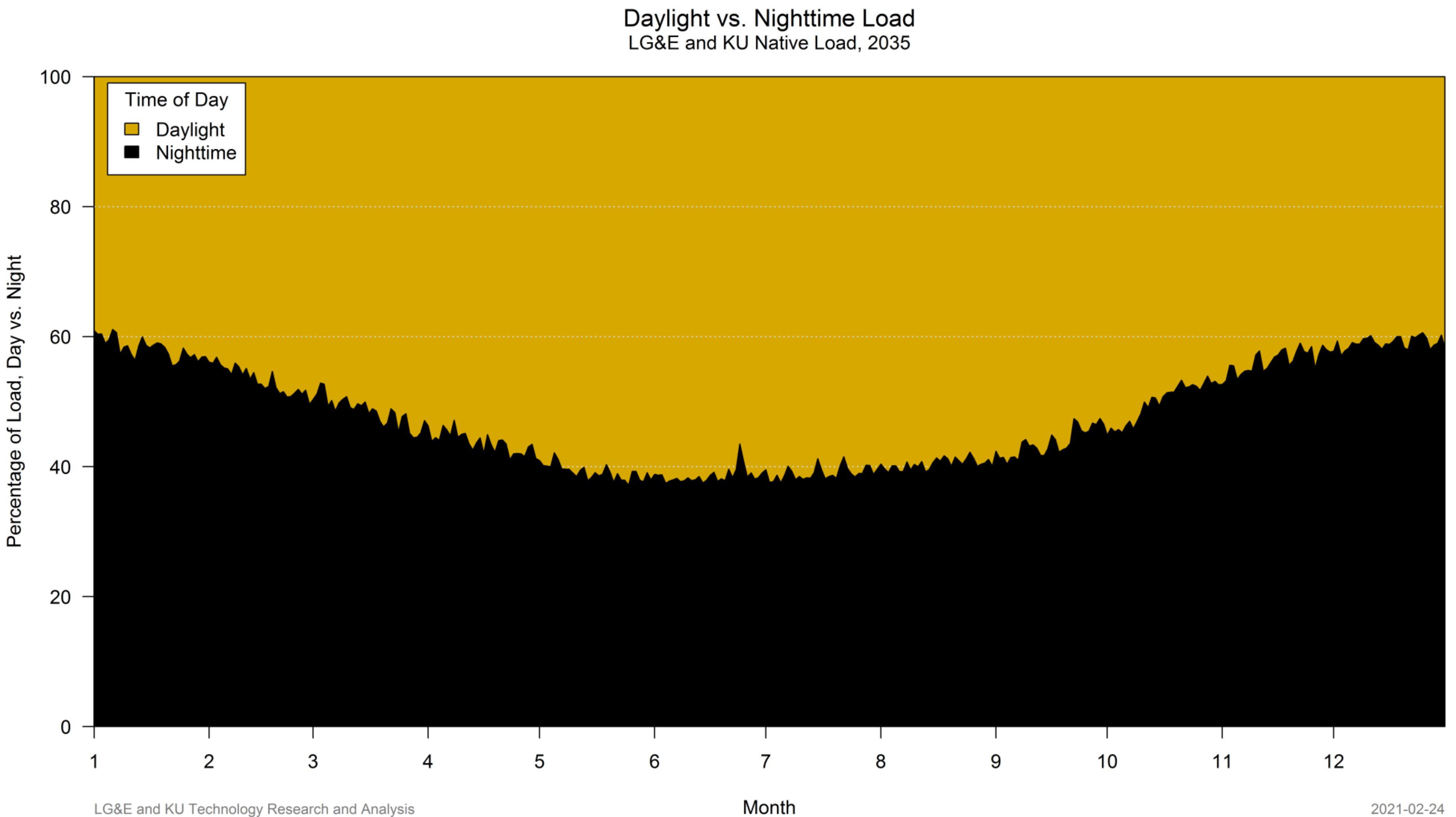
LG&E KU PPL companies

# 60% of LG&E and KU winter demand occurs at night

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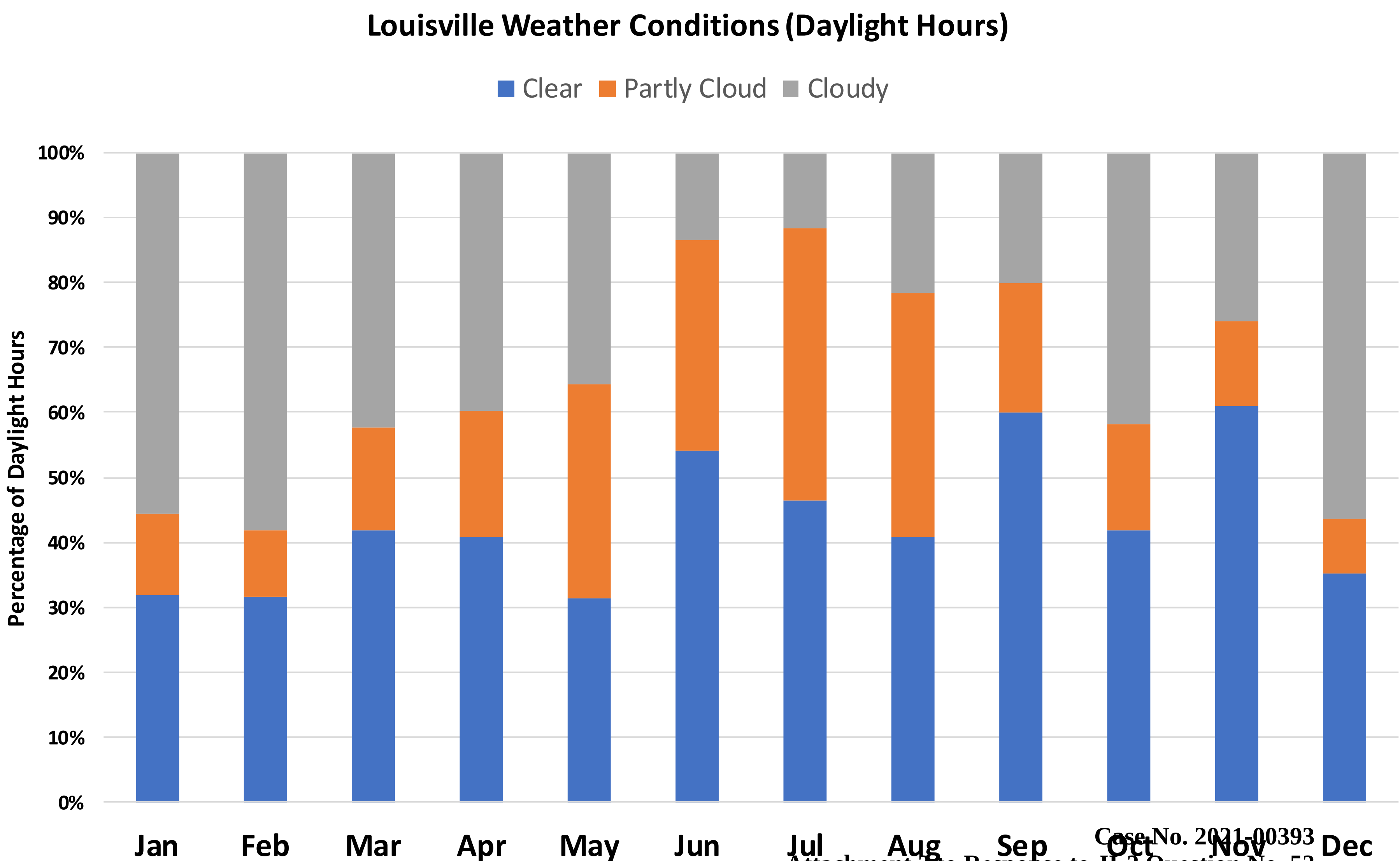
# The sky is usually cloudy in the winter

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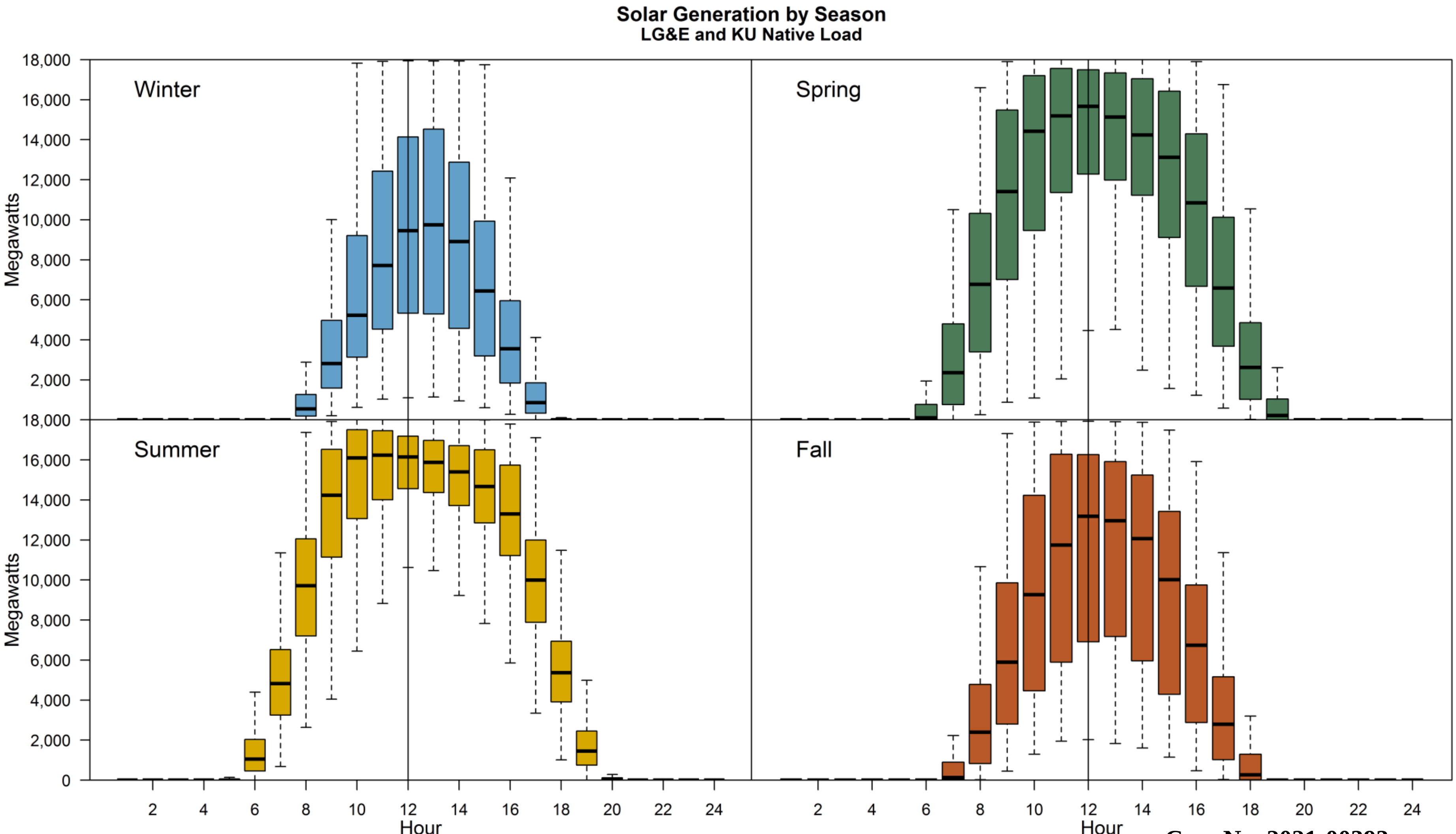
# Solar is availability varies by time and season

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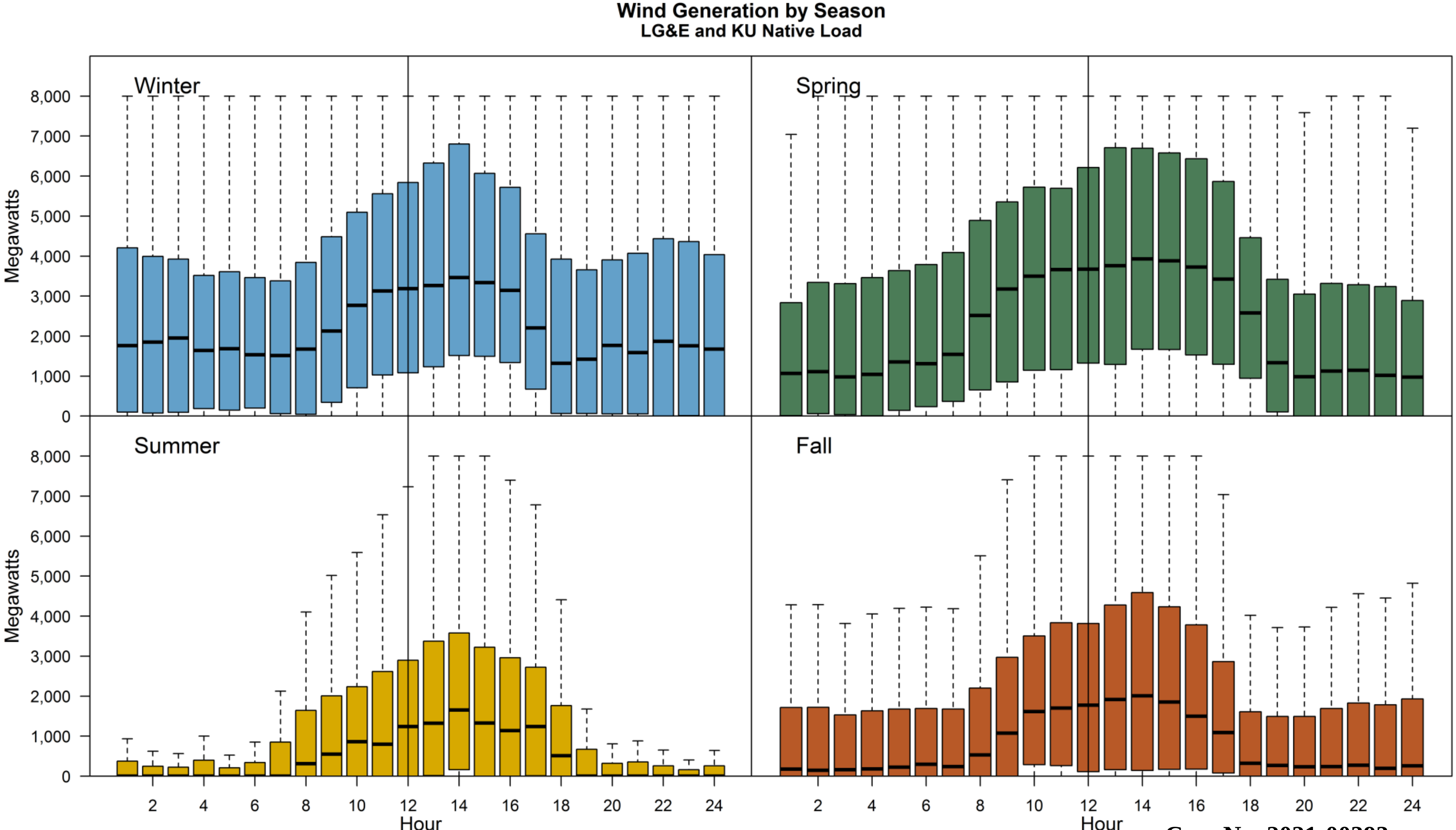
# Wind generation is best in winter and spring

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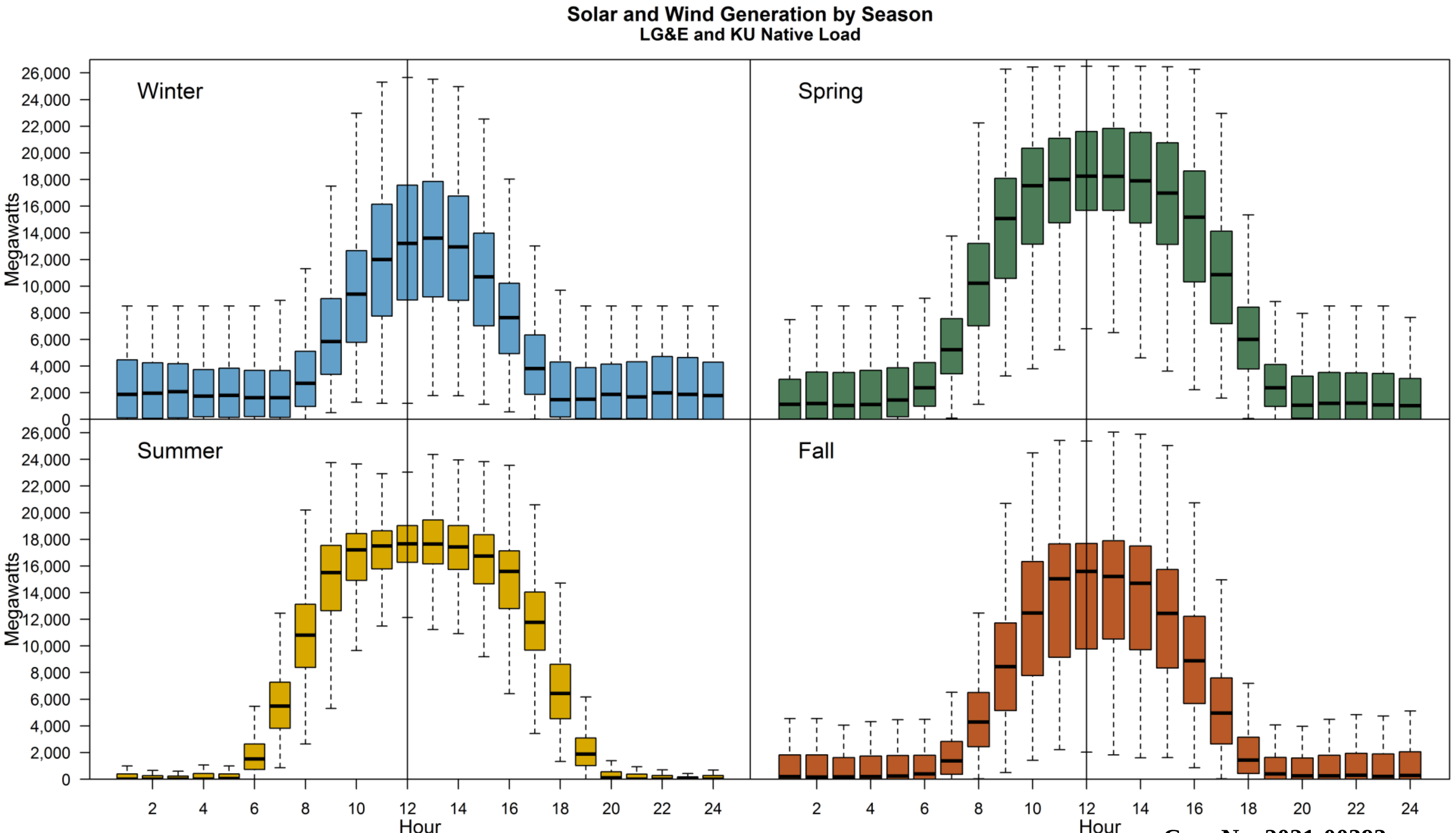
LG&E KU PPL companies

# Solar and wind power combined vary by season

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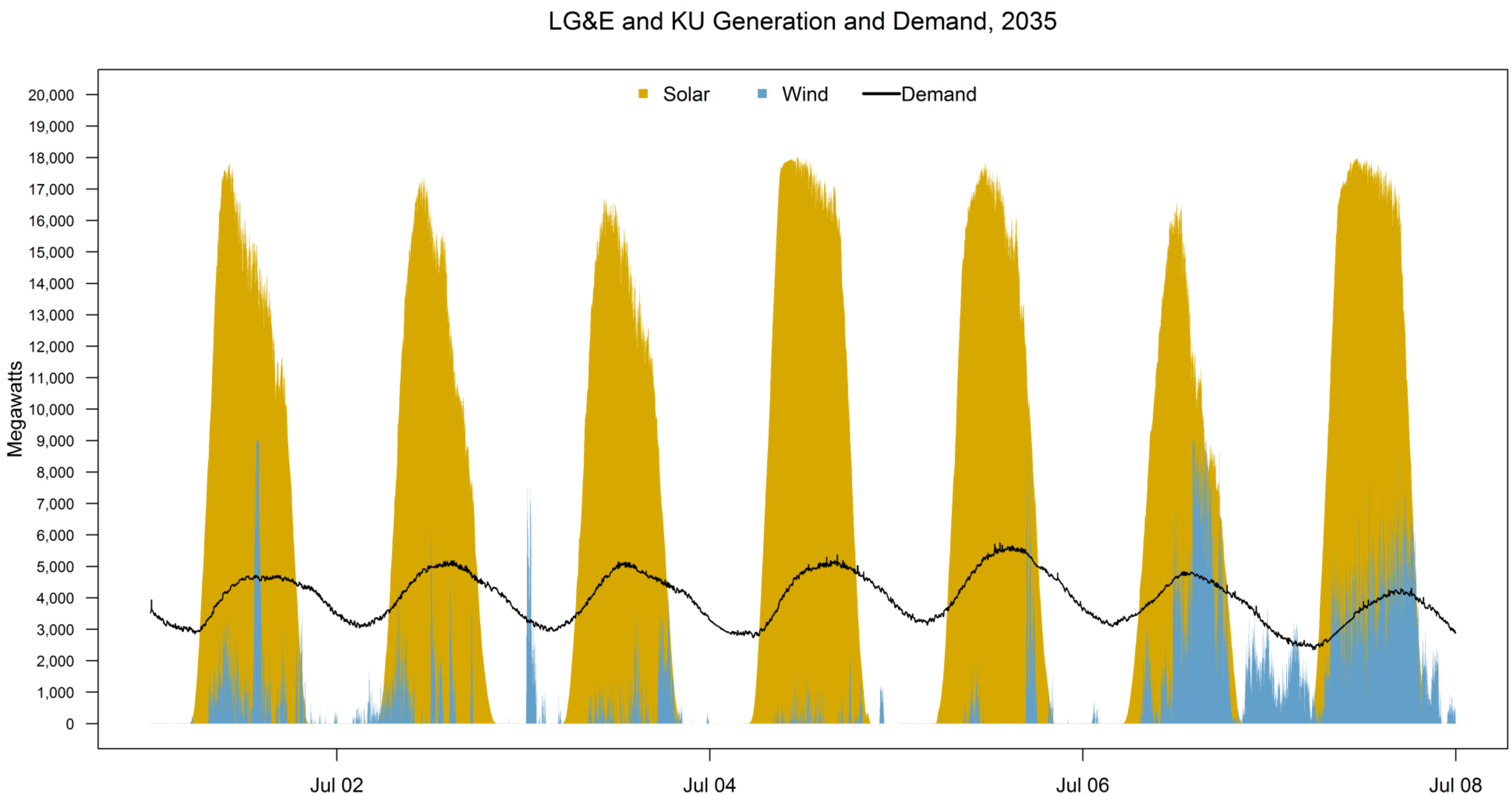
# 100% Renewable Scenario

# Solar capacity sized to meet winter needs causes excess generation in the summer

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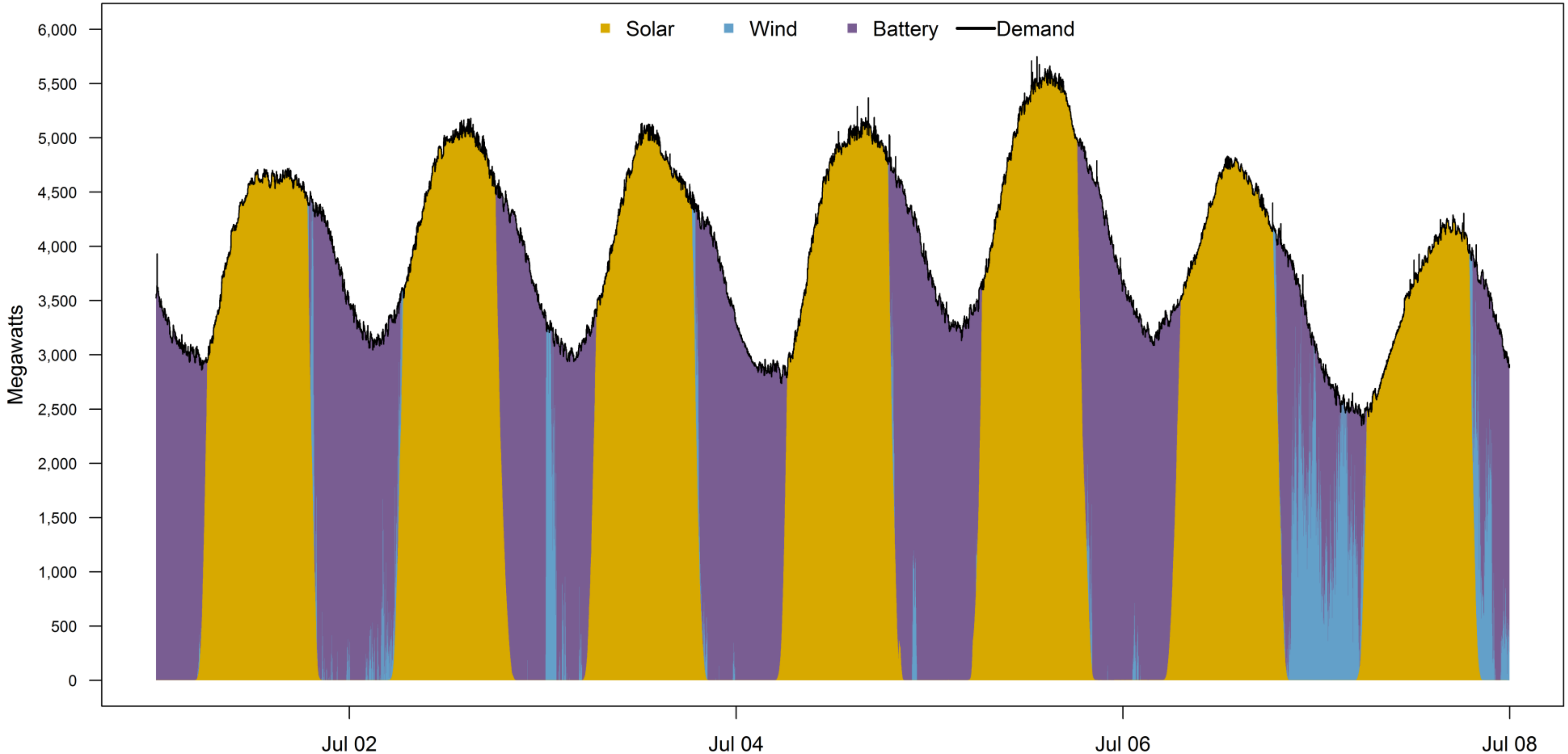
# Minimal wind generation in the summer requires batteries to meet night-time load

LG&E and KU Load Service Summer, 2035

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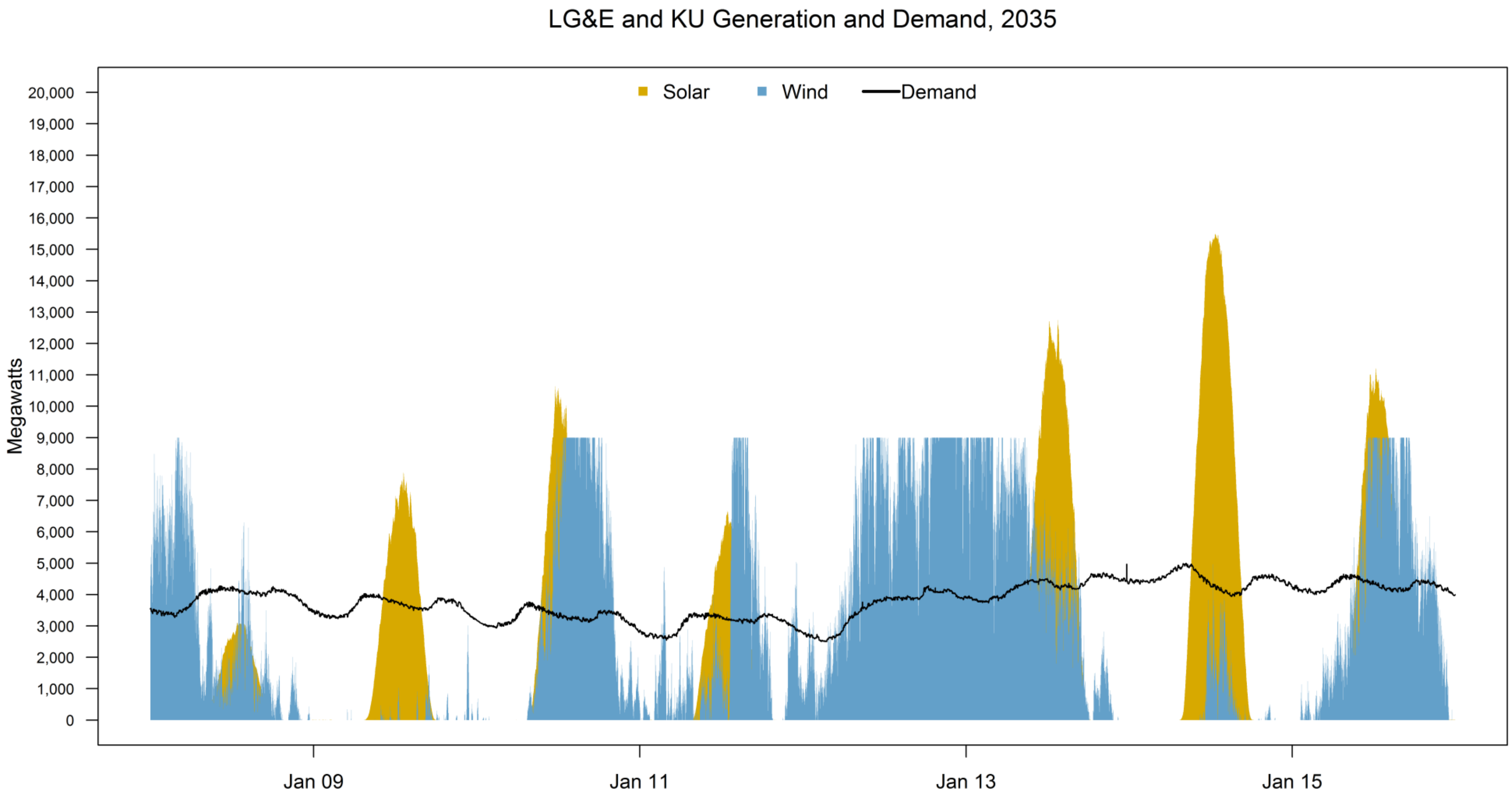
# Clouds, shorter days, and night-time load cannot be overcome with wind in the winter

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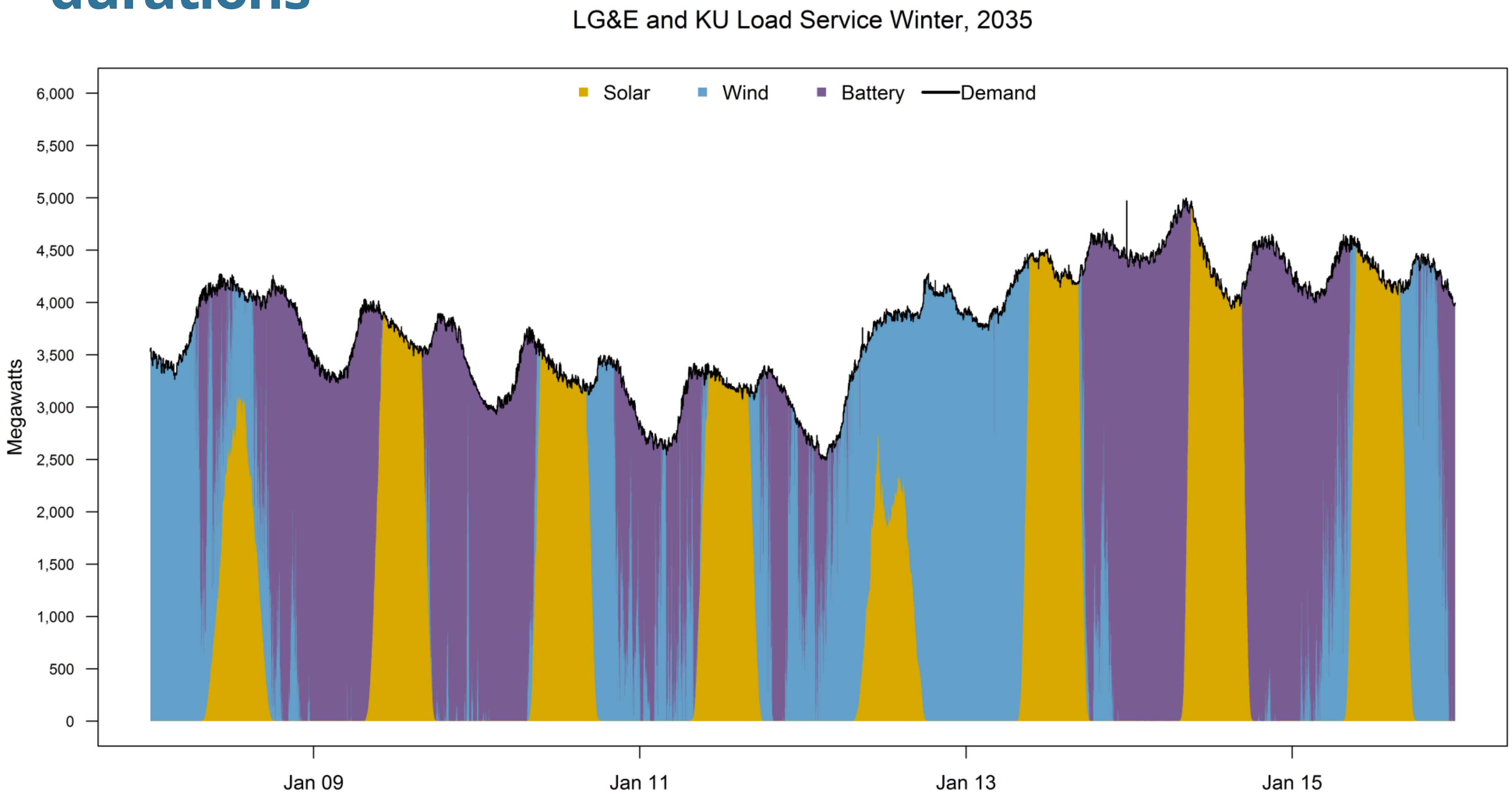
# Even in a sunny/windy winter week, batteries may be required to serve high percentage of load for long durations

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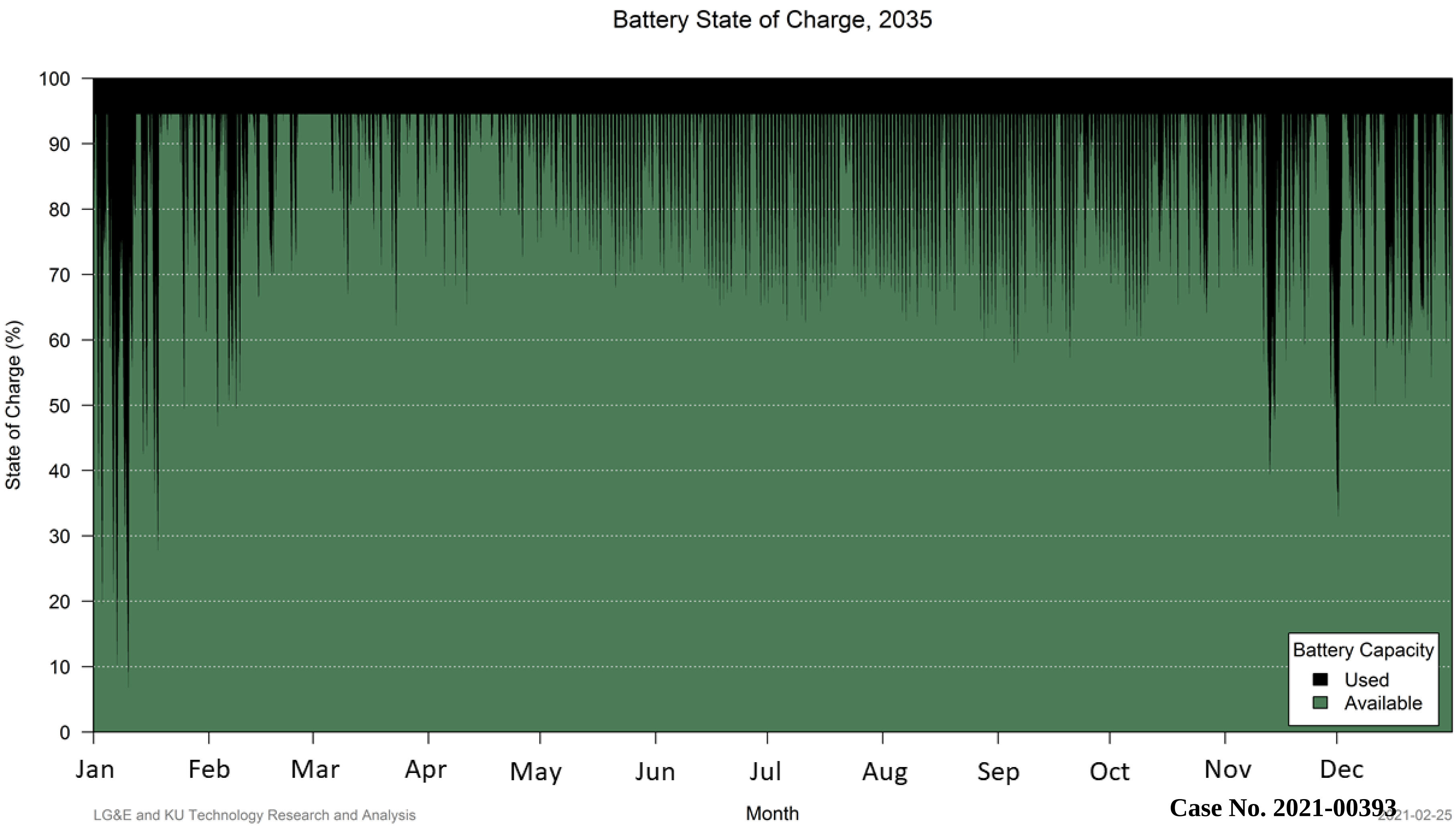
LG&E KU PPL companies

# Battery sized to meet cold, dark winter weeks while in summer, they have daily charge/discharge cycle

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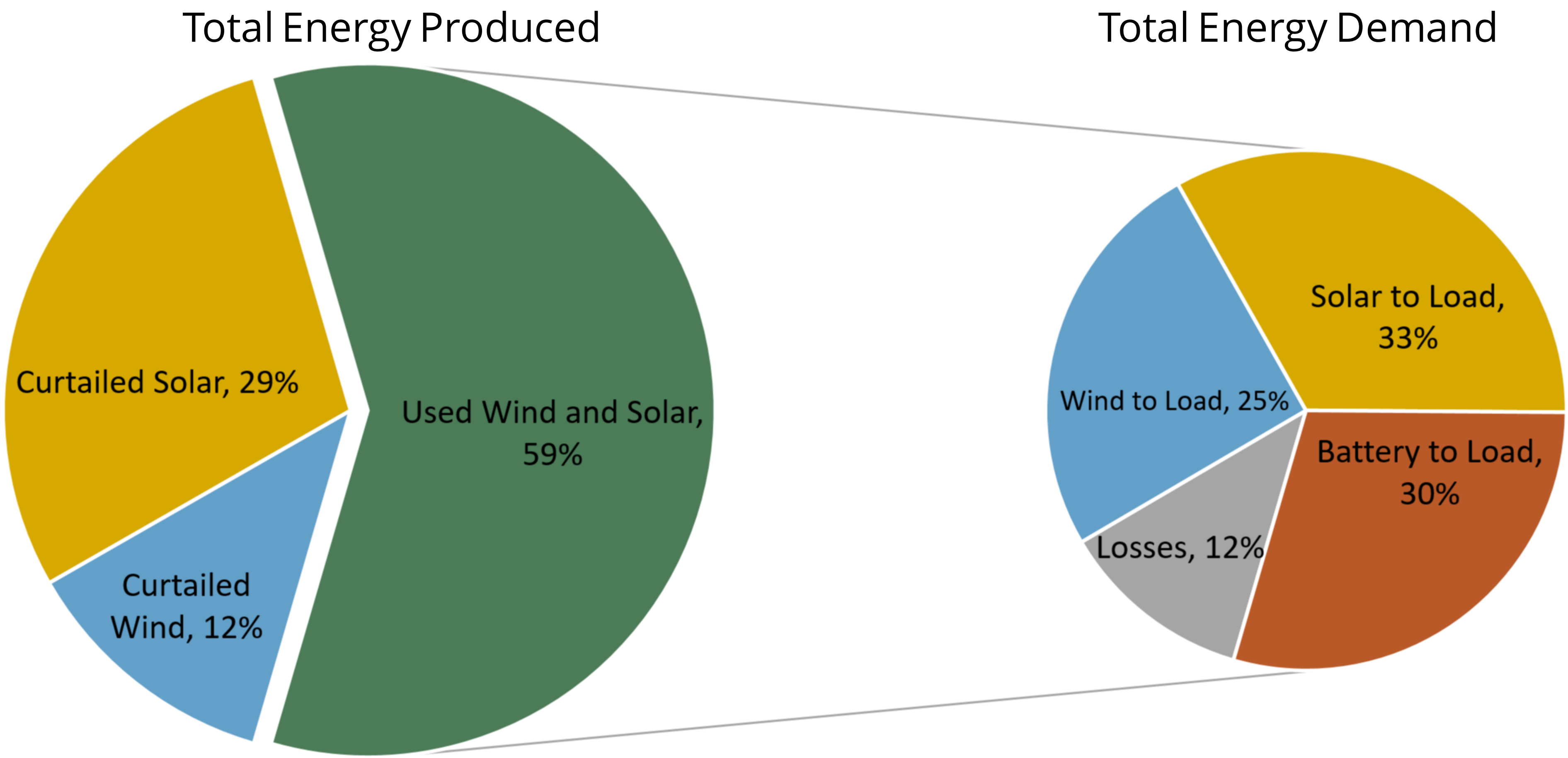
# 41% of solar and wind must be curtailed

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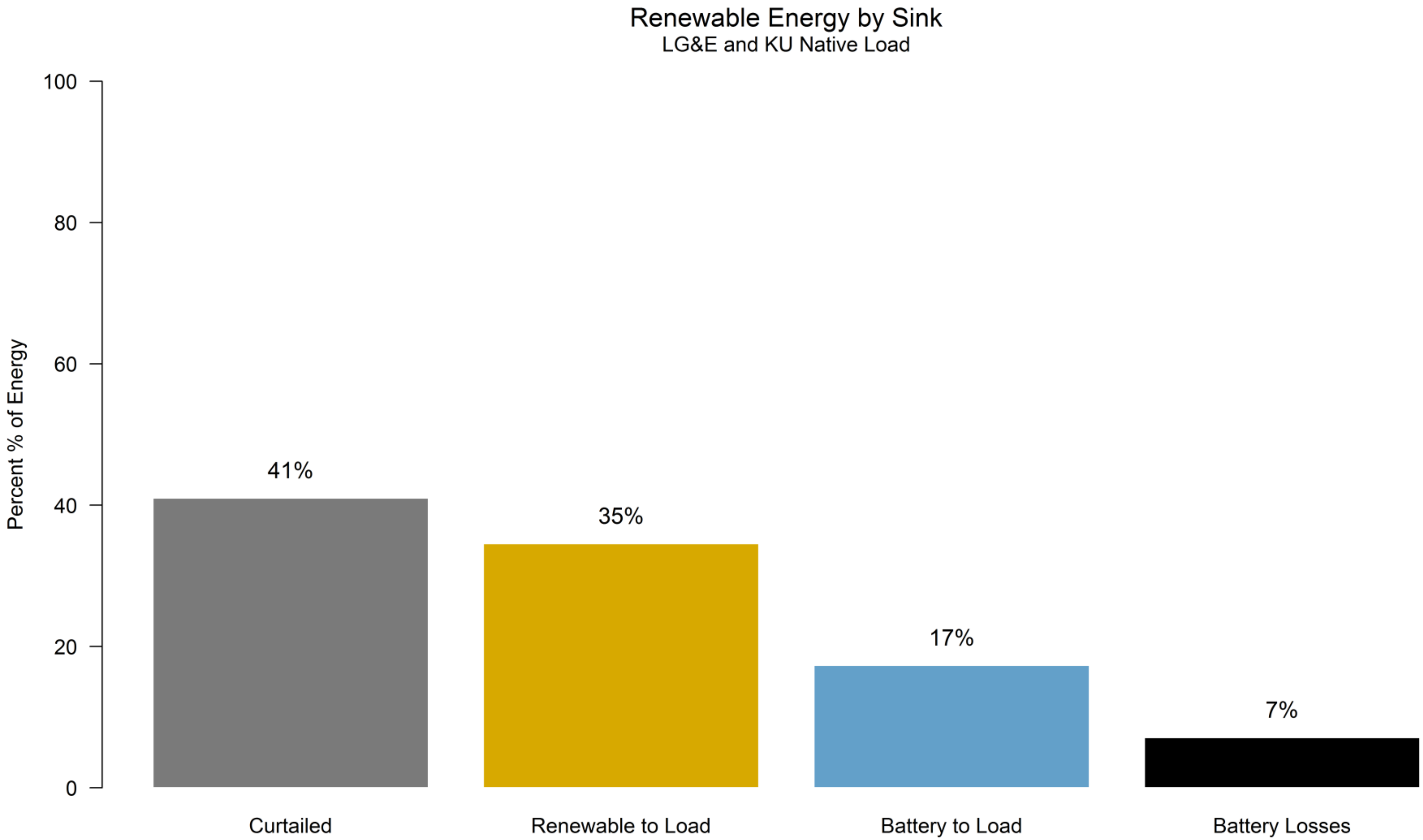
# 41% of solar and wind must be curtailed




LG&E and KU Technology Research and Analysis

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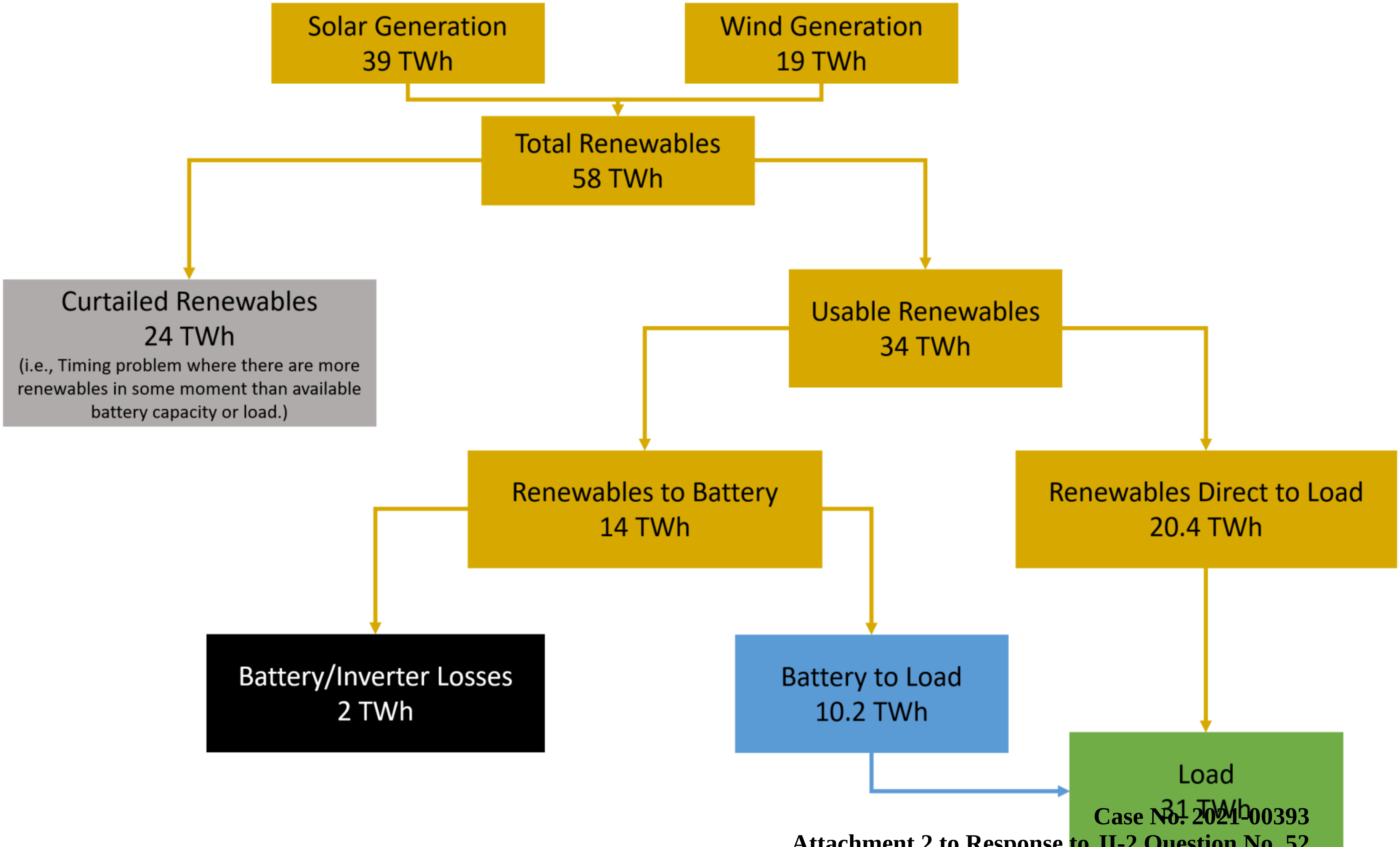
# Energy by Source and Sink

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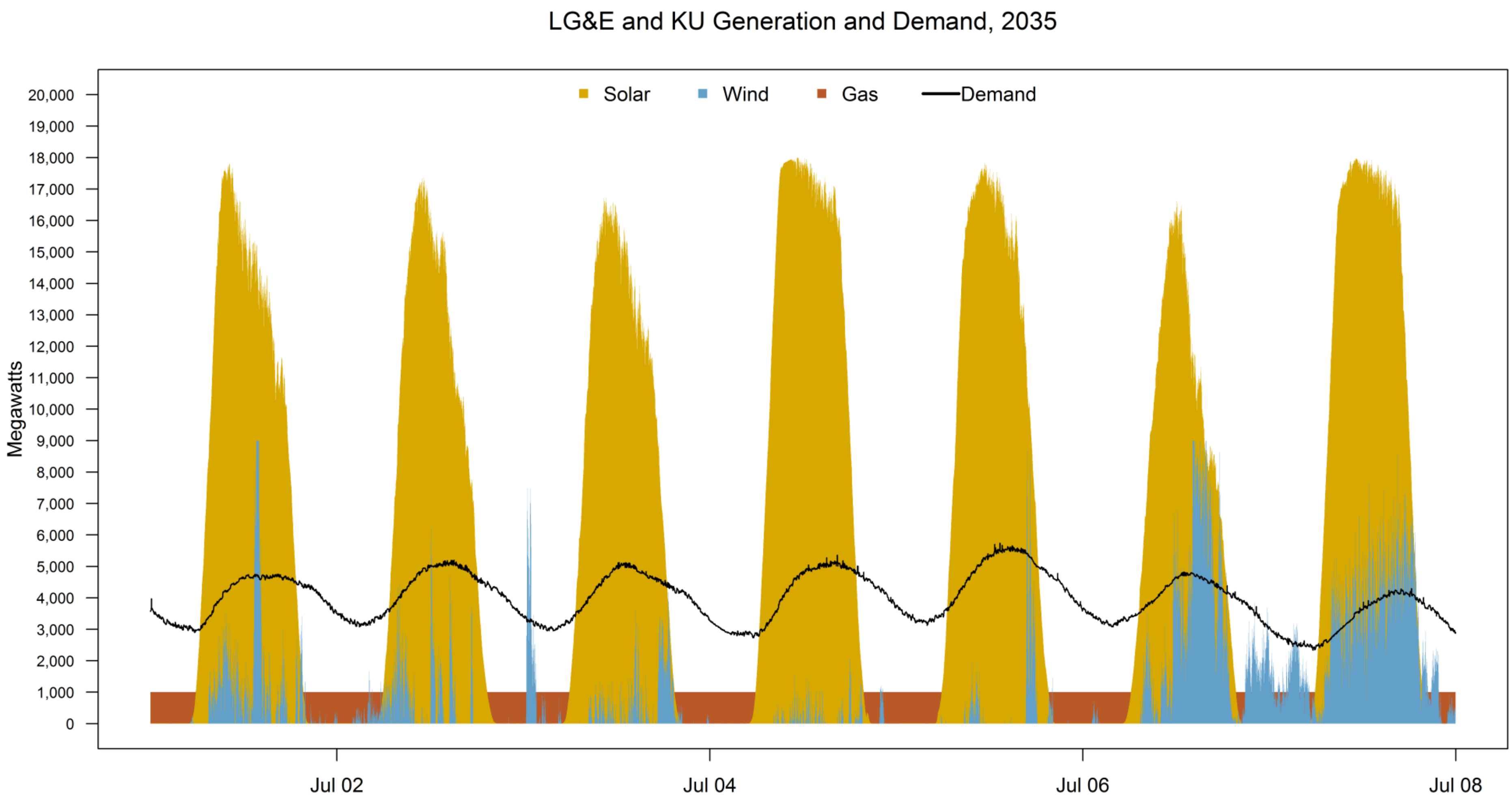
# 90% Carbon Reduction Scenario

# Solar capacity sized to meet winter needs causes excess generation in the summer

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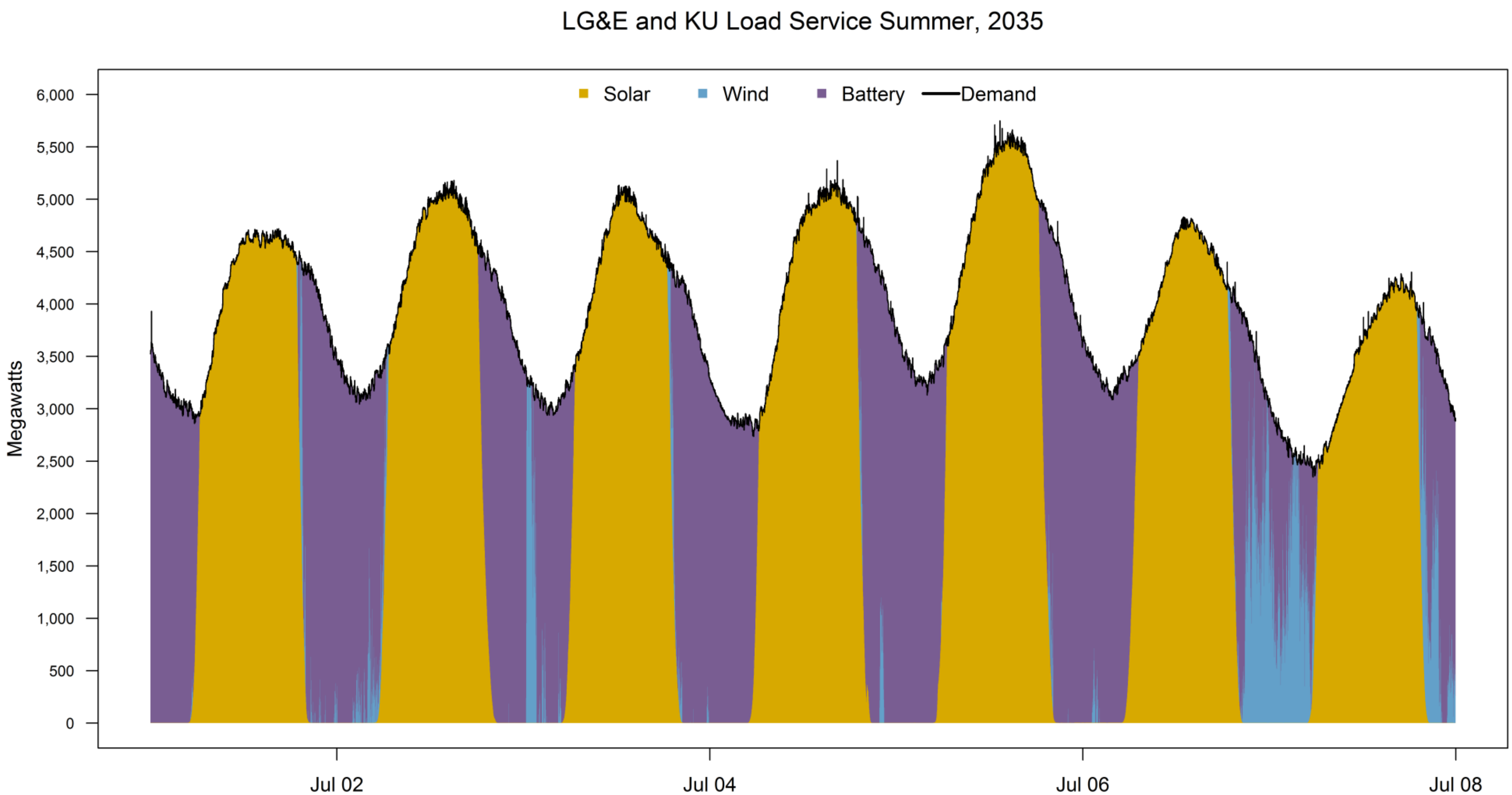
LG&E KU PPL companies

# Minimal wind generation in the summer requires batteries to meet night-time load

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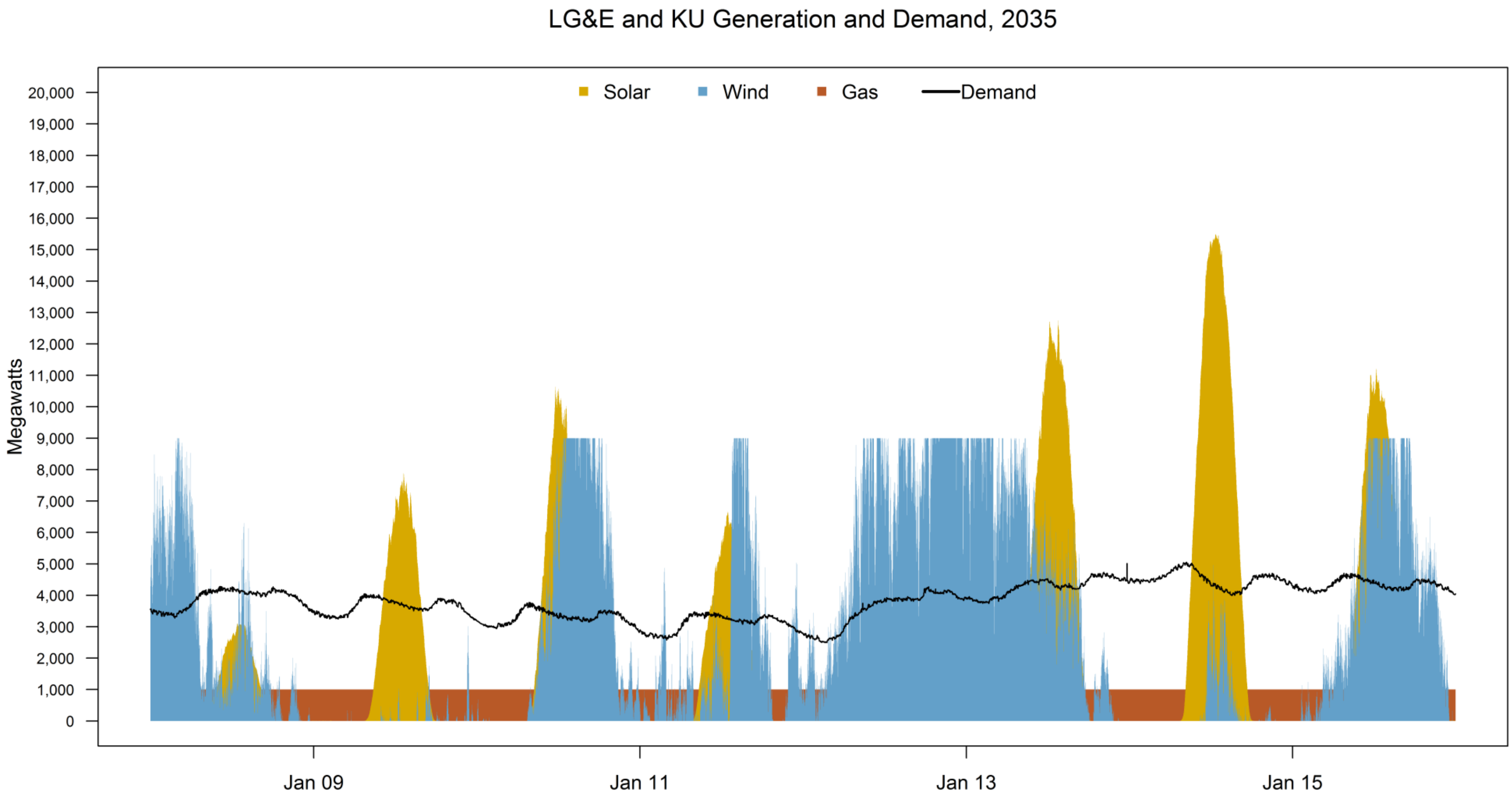
# Clouds, shorter days, and night-time load cannot be overcome with wind in the winter

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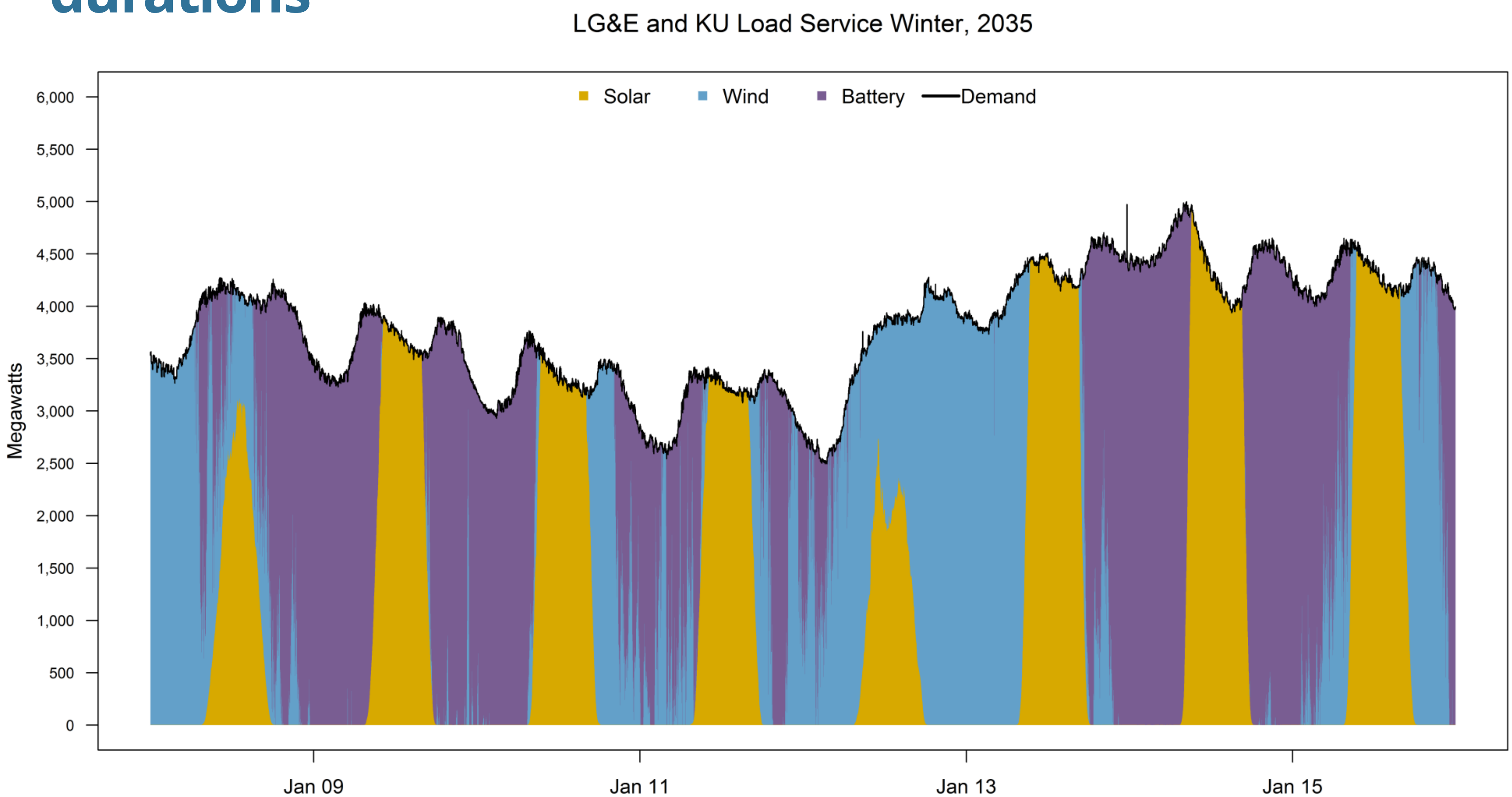
# Even in a sunny/windy winter week, batteries may be required to serve high percentage of load for long durations

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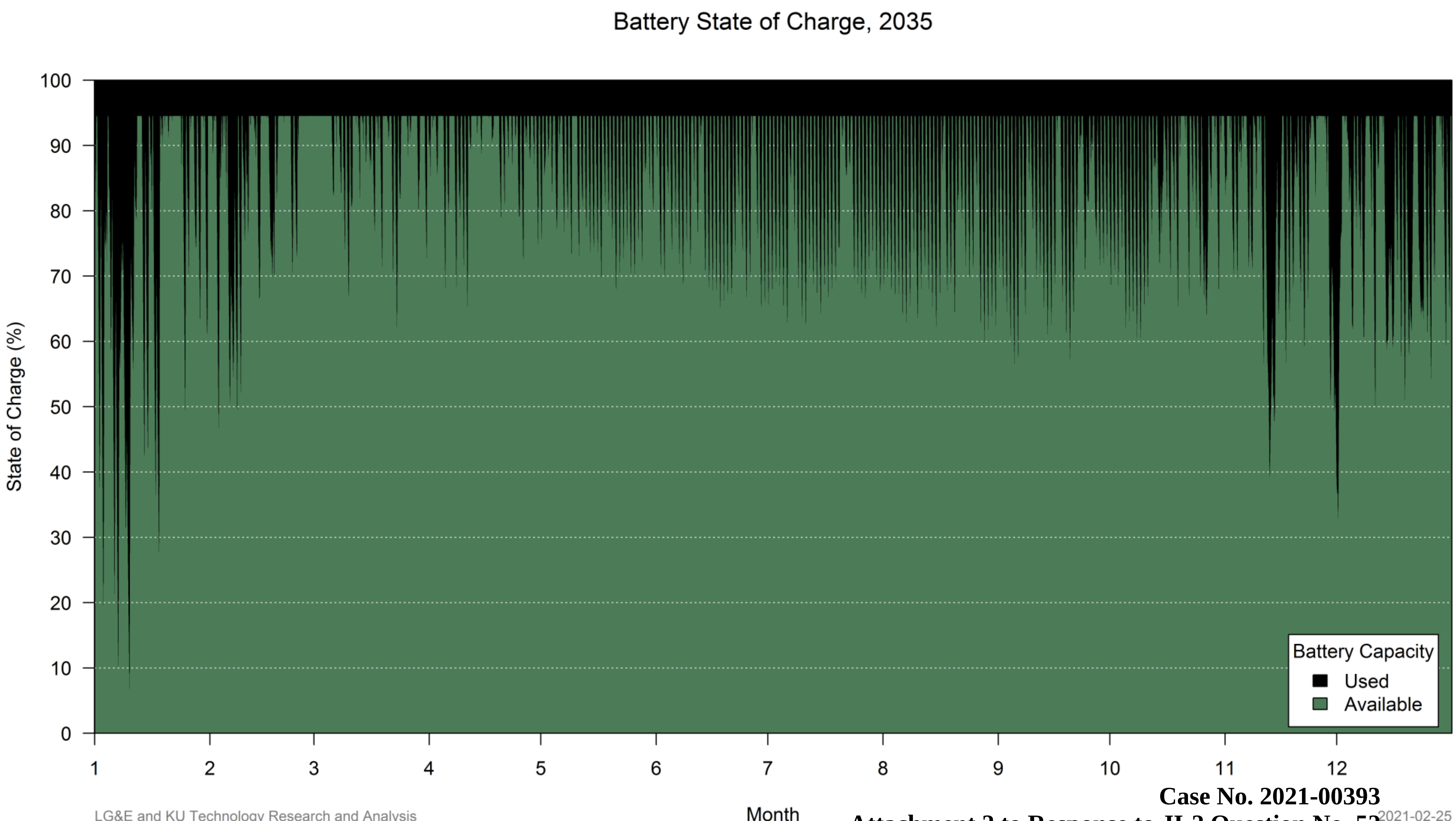
# Battery sized to meet cold, dark winter weeks while in summer, they have daily charge/discharge cycle

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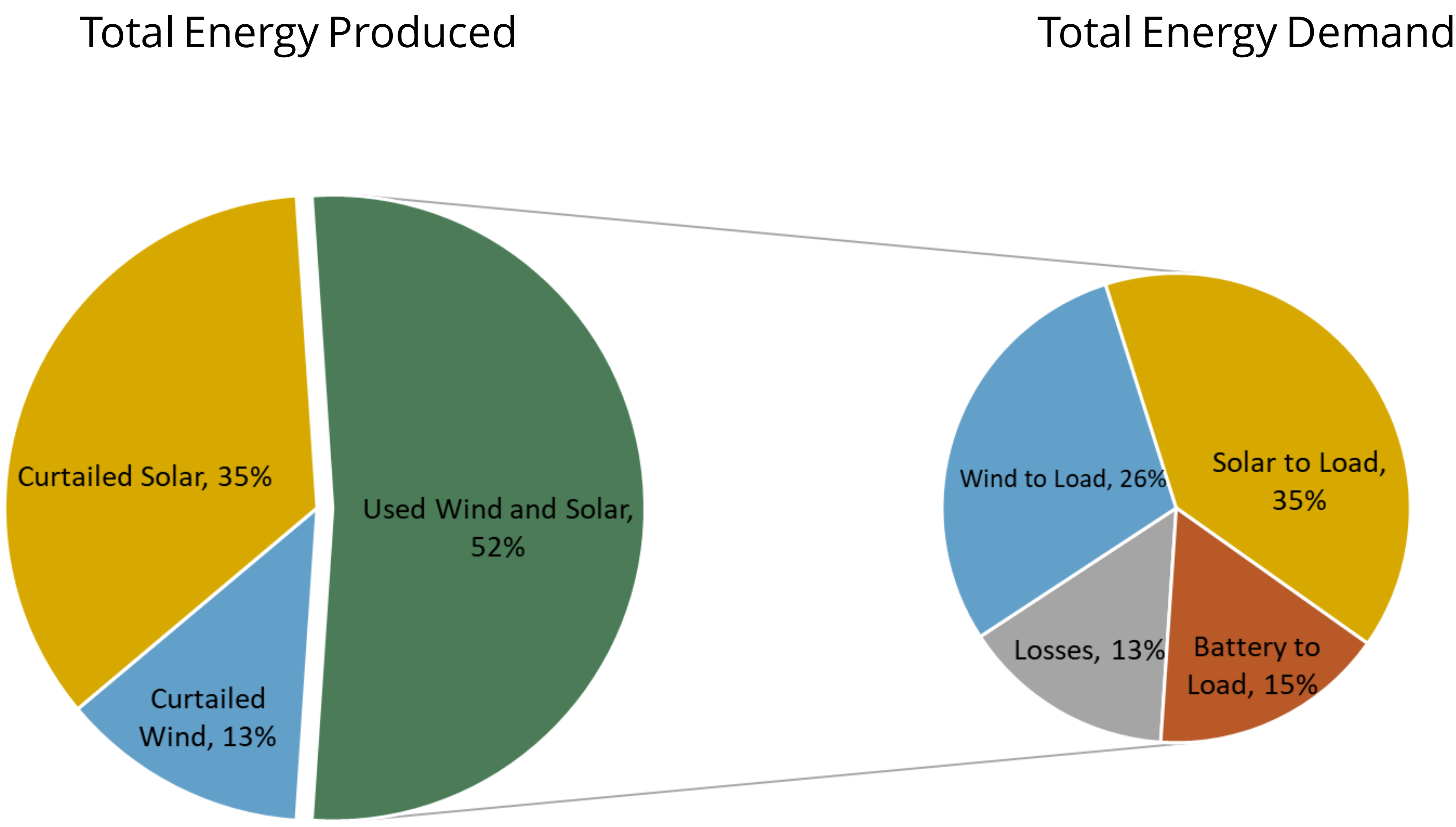
# 48% of solar and wind must be curtailed

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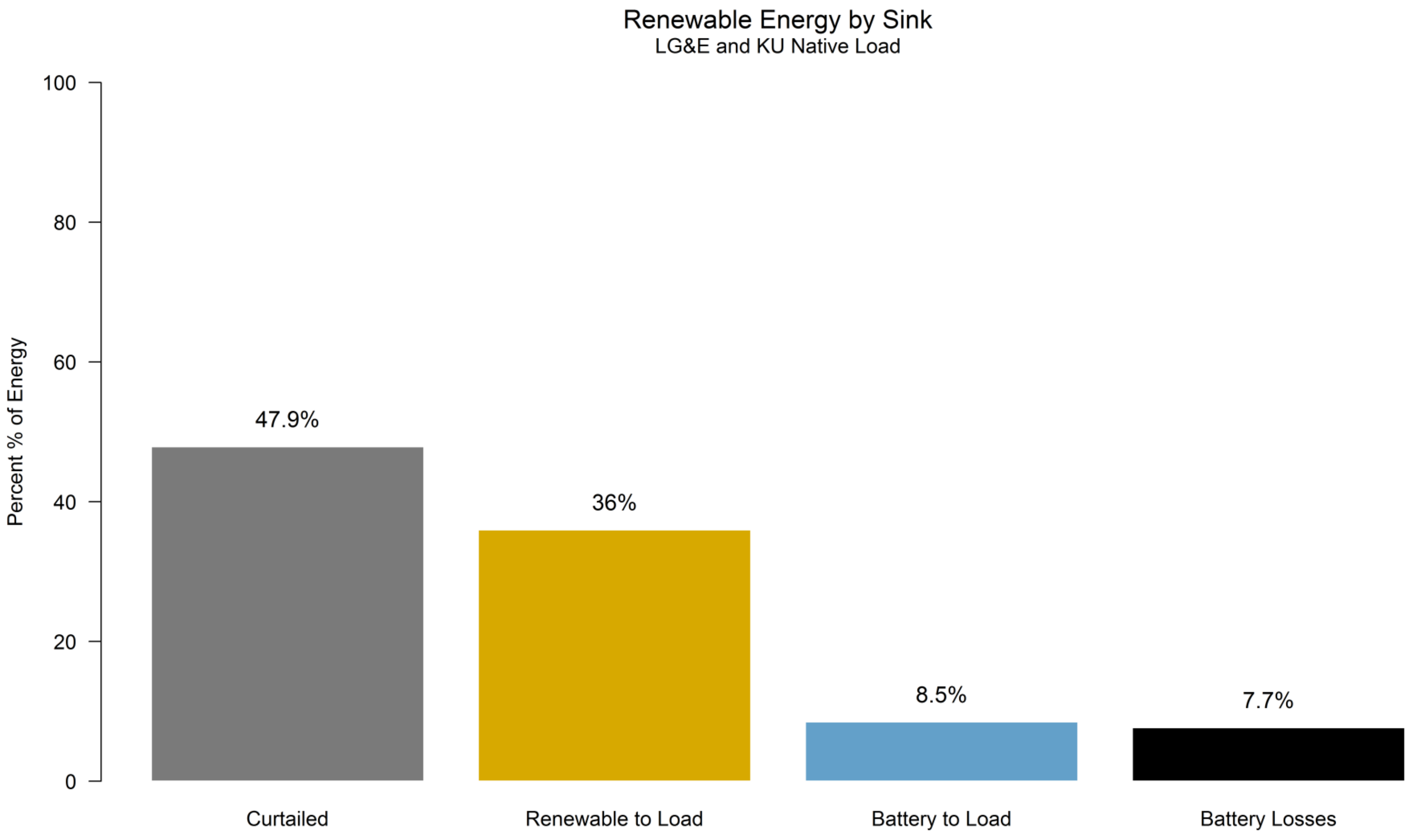
LG&E KU PPL companies

# 48% of solar and wind must be curtailed

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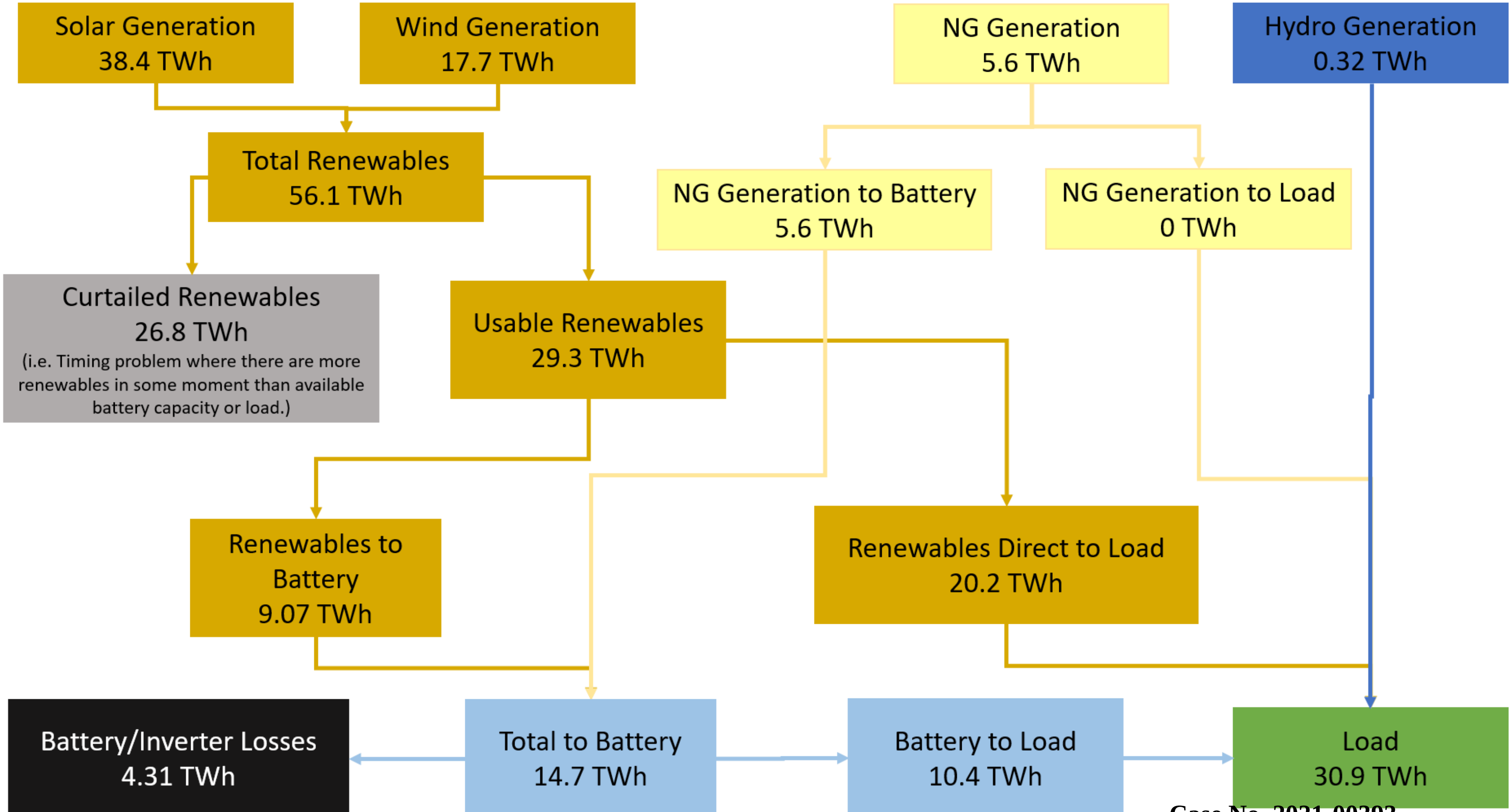
LG&E KU PPL companies

# Energy by Source and Sink

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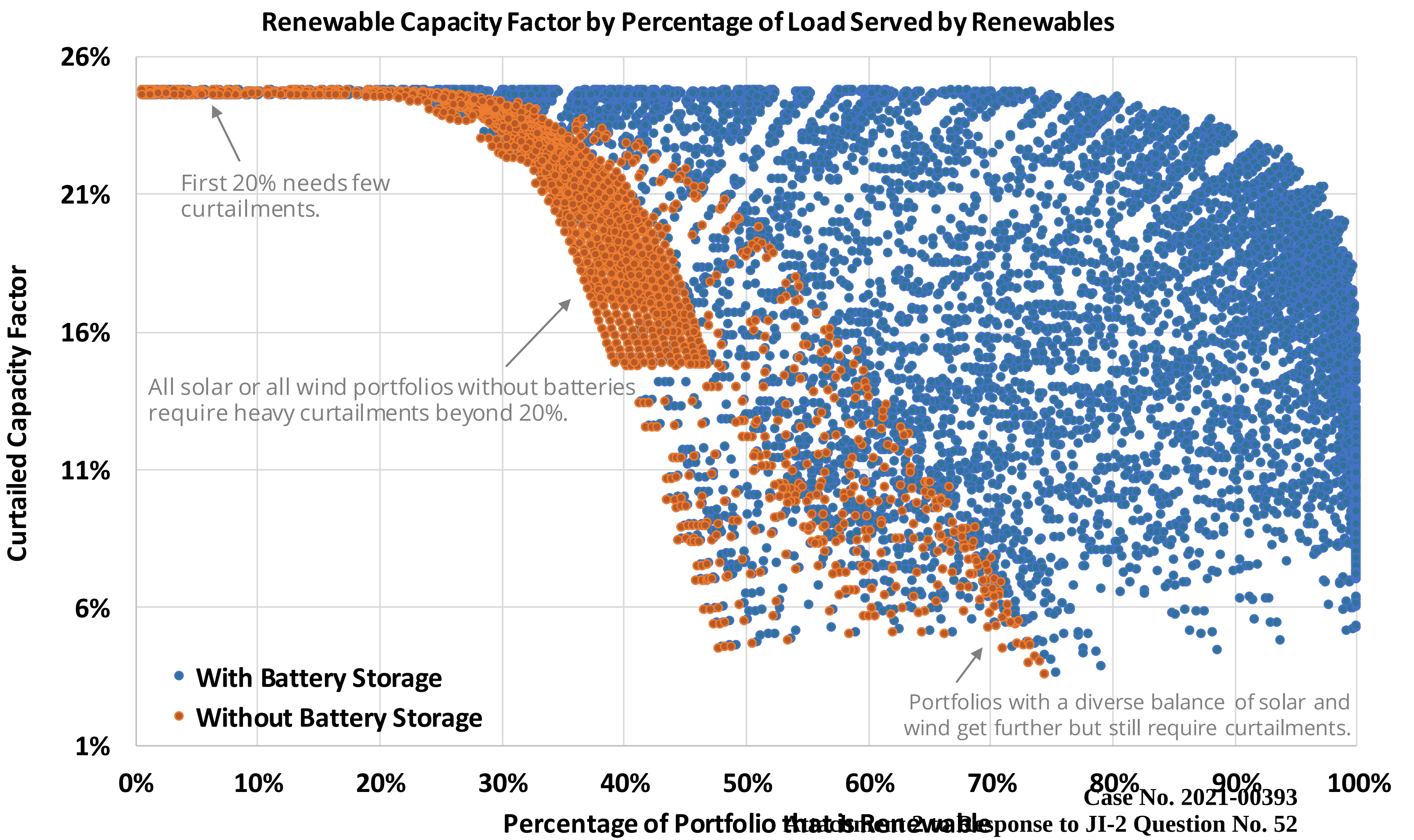
# Additional Data

# Beyond 20% of annual energy, renewable energy must be curtailed absent storage

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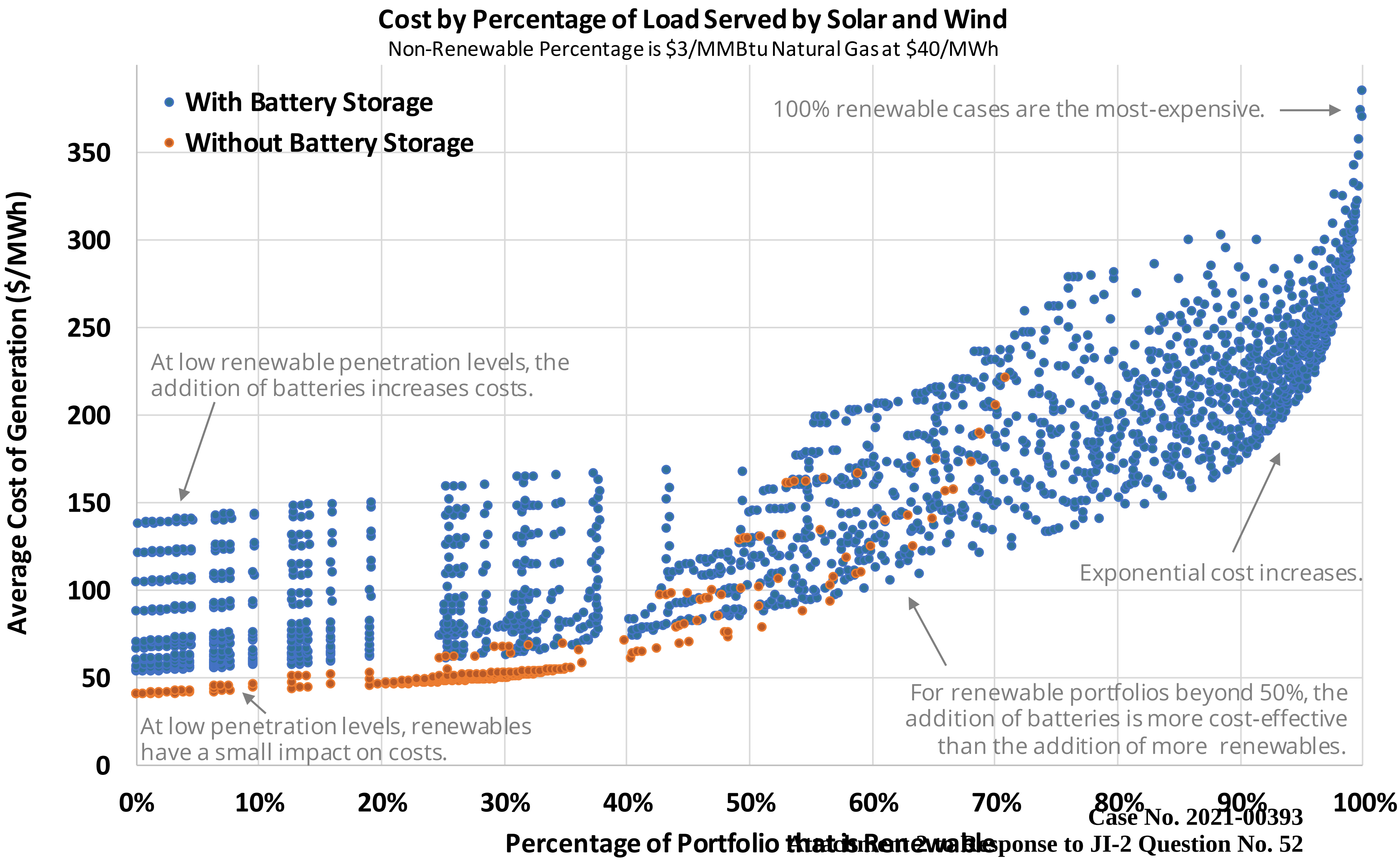
# Due to timing, the need for curtailments, and the need for batteries, renewable portfolio costs accelerate rapidly after 35% and exponentially after 85%

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LG&E KU PPL companies

The attachments are being provided in separate files in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.53**

**Responding Witness: David S. Sinclair**

Q-2.53. The Biden Administration just placed the "social cost of carbon" (SCC) for a ton of CO2 emitted in 2020 at $51. Meanwhile, economists Nicholas Stern and Joseph Stiglitz suggested a value around $100 per ton by 2030; Carleton and a colleague set it at about $125 per ton of carbon in a paper published in January; and Frances Moore, an environmental economist at the University of California at Davis, put it at $220 per ton in the estimate she and a colleague produced in 2015. What value do the companies place or reference for the SCC?

A-2.53. The Companies do not have a value that they "place or reference for the SCC." The Commission has explicitly stated, "The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service." Thus, even if the Companies had assigned a value for SCC, the Commission's own orders would preclude it from considering SCC.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.54**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.54. Please provide all data for the projected annual carbon dioxide and methane emissions that would be produced by the Companies under the plan proposed in the IRP. Include the percent change this represents relative to the Companies' emissions in 2021 and 2010.

A-2.54. The Companies did not explicitly calculate methane emissions for the IRP. The table below reflects projected carbon dioxide emissions from the base load, base fuel price case compared against 2021 and 2010 emissions. The forecast values reflect results from the detailed hourly dispatch PROSYM model.[23]

[23] The Companies used PROSYM to model detailed annual production costs and PLEXOS for expansion planning, which results in immaterial differences in $CO_2$ emissions.

| Year | Annual $CO_2$ Emissions (000s tons) | | |
|---|---|---|---|
| | 2021 IRP Base Load, Base Fuel | % Change from 2010 | % Change from 2021 |
| 2010 Actual | 35,843 | -- | -- |
| 2021 Actual | 29,824 | -17% | -- |
| 2022 | 28,995 | -19% | -3% |
| 2023 | 29,331 | -18% | -2% |
| 2024 | 29,395 | -18% | -1% |
| 2025 | 28,270 | -21% | -5% |
| 2026 | 28,240 | -21% | -5% |
| 2027 | 27,942 | -22% | -6% |
| 2028 | 26,557 | -26% | -11% |
| 2029 | 26,068 | -27% | -13% |
| 2030 | 25,956 | -28% | -13% |
| 2031 | 26,047 | -27% | -13% |
| 2032 | 26,301 | -27% | -12% |
| 2033 | 26,040 | -27% | -13% |
| 2034 | 21,248 | -41% | -29% |
| 2035 | 21,432 | -40% | -28% |
| 2036 | 21,450 | -40% | -28% |

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.55**

**Responding Witness: David S. Sinclair**

Q-2.55. With regard to methane (also referred to as natural gas):

a. Please describe all measures the Companies take to monitor, control, prevent, and repair methane leaks in all of its infrastructure, including pipelines, meters, storage facilities, and generation plants.

b. Please provide any and all data and reports produced by the Companies regarding methane leakage from 2016 to 2021.

c. What plans and goals do the companies have to reduce methane emissions during the planning period?

d. How were methane emissions factored into the Companies' IRP planning process, risk assessments, and cost-benefit analyses?

e. Please provide the following data for the past five years:
    i. Natural gas wholesale purchases (volumetric) for re-sale to customers and for power generation
    ii. Natural gas production from wells owned by the Companies
    iii. Natural gas volumes sold to customers
    iv. Natural gas volumes burned for electricity generation
    v. Amount of natural gas lost between the source (where the Companies acquire the gas) and the end-use (when it passes through the customer's meter or when burned in a generator)

A-2.55. The IRP concerns electric load and electric generation; it does not relate to natural gas service, so all parts of this request pertaining to natural gas service are not relevant to the IRP. Also, the Companies are not subject to methane emissions restrictions. Therefore, the Companies did not account for methane emissions in the IRP.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.56**

**Responding Witness: David S. Sinclair**

Q-2.56. In this time of climate crisis, felt by our entire community and country, why do the Companies express little sense of urgency, or commitment to community responsibility, participation, and collaboration? Why do they seem to minimize the public interest?

A-2.56. The Companies take issue with all of the premises of this request, which is highly argumentative. The Companies take seriously their obligation to serve all customers safely, reliably, and at the lowest reasonable cost. See also the response to Question No. 2.51.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.57**

**Responding Witness: David S. Sinclair**

Q-2.57. In comparing and evaluating possible resource additions and retirements (including distributed generation) do the companies include the costs of pollutants and environmental damage, negative health impacts, and the potential avoided costs of these (such as those costs quantified in: https://www.epa.gov/statelocalenergy/public-health-benefits-kwh- energy-efficiency-and-renewable-energy-united-states; and https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf)?

A-2.57. The Companies account for applicable environmental regulations and requirements in their IRP. The IRP does not address externalities. See the responses to Question Nos. 2.13 and 2.53.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.58**

**Responding Witness: David S. Sinclair**

Q-2.58. Please provide details of all participation by the Companies in Merchant Solar developments not described in the IRP, and how such developments are connected to the Companies' operations described in the IRP.

A-2.58. It is unclear to what this request refers. That aside and irrespective of the Companies' participation, there are no merchant solar developments not described in the IRP that are connected to the Companies' operations described in the IRP.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.59**

**Responding Witness: David S. Sinclair**

Q-2.59. Regarding the research conducted at the EW Brown Station solar and battery storage facility, please provide each of the research reports and presentations referenced on p.108 of Volume I.

a. Provide all reports and data available concerning vegetation management and grazing at the EW Brown solar field.

A-2.59.

The following published reports cover vegetation management and grazing at the E.W. Brown solar farm.

Electric Power Research Institute. *Solar Grazing: Viability of Grazing Sheep for Vegetation Management*. EPRI, Palo Alto, CA: 2020. 3002020204. https://www.epri.com/research/products/000000003002020204

Electric Power Research Institute. *Solar Grazing: Viability of Grazing Sheep for Vegetation Management, Year 2*. EPRI, Palo Alto, CA: 2022. 3002023328. https://www.epri.com/research/products/000000003002023328

Electric Power Research Institute. *Louisville Gas & Electric and Kentucky Utilities — Demonstrating the Use of Pollinator Habitat at Solar Sites*. EPRI, Palo Alto, CA: 2020. 3002020213. https://www.epri.com/research/products/000000003002020213

The reports published from research at the E.W. Brown energy storage site are listed below and are also posted online at lge-ku.com/research.

Akeyo O.M., Rallabandi V., Jewell N., Patrick A., Ionel D.M. "Parameter Identification for Cells, Modules, Racks, and Battery for Utility-Scale Energy Storage Systems." *IEEE Access* 8 (2020): 215817-215826, doi: 10.1109/ACCESS.2020.3039198.

https://sparklab.engr.uky.edu/sites/sparklab/files/2020%20Access%20UKspark%20BESS%20Characterization_0.pdf

Akeyo O.M., Rallabandi V., Jewell N., Ionel D.M. "The Design and Analysis of Large Solar PV Farm Configurations With DC-Connected Battery Systems." *IEEE Transactions on Industry Applications* 56, 3. (2020): 2903-2912, doi: 10.1109/TIA.2020.2969102. https://sparklab.engr.uky.edu/sites/sparklab/files/2019%20IAS%20UKSpark%20DC%20Bus%20connected%20BESS.pdf

Zhang Y., Akeyo O.M., He J., Ionel D.M. "On the Control of a Solid State Transformer for Multi-MW Utility-Scale PV-Battery Systems." *2019 IEEE Energy Conversion Congress and Exposition (ECCE).* (2019): 1-6, https://sparklab.engr.uky.edu/sites/sparklab/files/2019%20IEEE%20ECCE%20UKSpark%20SST%20Solid%20State%20Transformer%20Multi%20MW%20PV.pdf

Akeyo O.M., Rallabandi V., Jewell N., Ionel D.M. "Measurement and Estimation of the Equivalent Circuit Parameters for Multi-MW Battery Systems." *2019 IEEE Energy Conversion Congress and Exposition (ECCE).* (2019): 2499-2504, doi: 10.1109/ECCE.2019.8912233. https://sparklab.engr.uky.edu/sites/sparklab/files/2019%20ECCE%20UKspark%20BESS%20Characterization_0.pdf

Akeyo O.M., Rallabandi V., Jewell N., Ionel D.M. "Modeling and Simulation of a Utility-Scale Battery Energy Storage System." *2019 Power & Energy Society General Meeting (PESGM).* (2019): 1-5. https://sparklab.engr.uky.edu/sites/sparklab/files/2019%20PES%20UKSpark%20BESS%20Aux%20Function.pdf

Rallabandi V., Akeyo O.M., Jewell N., Ionel D.M. "Incorporating Battery Energy Storage Systems Into Multi-MW Grid Connected PV Systems." *IEEE Transactions on Industry Applications* 55, 1. (2019): 628-647, doi: 10.1109/TIA.2018.2864696. https://sparklab.engr.uky.edu/sites/sparklab/files/2019%20TransOnIAS%20UKSpark%20Multi%20MW%20PV%20BESS.pdf

Akeyo O.M., Gong H., Rallabandi V., Jewell N., Ionel D.M. "Power Utility Tests for Multi-MW High Energy Batteries." *2018 IEEE International Conference on Renewable Energy Research and Applications (ICRERA).* (2018): 1396-1399, doi: 10.1109/ICRERA.2018.8566920. https://sparklab.engr.uky.edu/sites/sparklab/files/2018%20ICRERA%20UKSpark%20EPRI%20Utility%20Test.pdf

Akeyo O.M., Rallabandi V., Jewell N., Ionel D.M. "Improving the Capacity Factor and Stability of Multi-MW Grid Connected PV Systems with Results from a 1MW/2MWh Battery Demonstrator." *2018 IEEE Energy Conversion Congress and Exposition (ECCE).* (2018): 2504-2509, doi: 10.1109/ECCE.2018.8558253. https://sparklab.engr.uky.edu/sites/sparklab/files/2018%20ECCE%20UKSpark%20PV%20Capacity%20factor_0.pdf

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.60**

**Responding Witness: Stuart A. Wilson**

Q-2.60. In reference to "Data Analytics" (p.109, Vol. I), please provide all data, analysis and reports resulting from modeling of "the minute-to- minute impacts of intermittent renewable generation on the Companies' transmission and generation systems." Please identify all software used for this modeling.

A-2.60. The reports published from modeling minutely intermittent renewable generation include:

Akeyo O.M., Patrick A., Ionel D.M. "Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System," *Energies* 14, 1. (2021): 169, doi: 10.3390/en14010169. https://www.mdpi.com/1996-1073/14/1/169

LG&E and KU Energy. "Using solar and storage to meet 100% of the electricity requirements of a distribution circuit." See the response to SREA 2-13d.

The Companies used R, Python, MATLAB, and PSS®E to model intermittent renewable generation in these analyses.

Also, see attached for other reports and analyses resulting from use of the Companies' modeling.

The data resulting from use of the Companies' modeling tools that is responsive to this request consumes numerous terabytes of storage space and consists of file types not usable by common software applications. Therefore, it is not feasible or useful to provide the modeling data requested, but the attached reports and analyses provide useful distillations of the data.

# Intermittent Solar Penetration Study

## Research Update 11/30/2020

Research Partnership with the University of Kentucky
Power and Energy Institute of Kentucky
By Akeyo Oluwaseun, Aron Patrick, and Dan Ionel

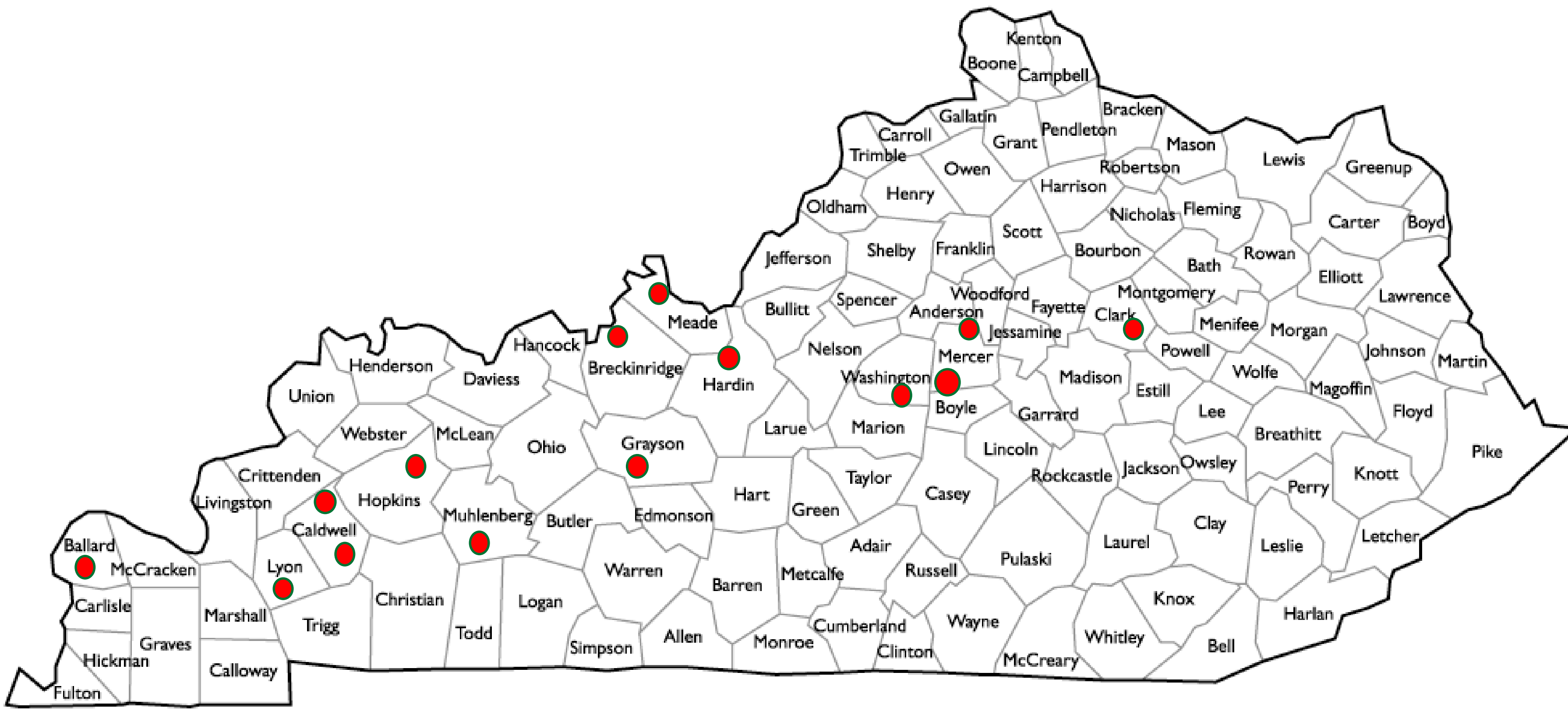
LG&E KU
PPL companies

# Executive Summary

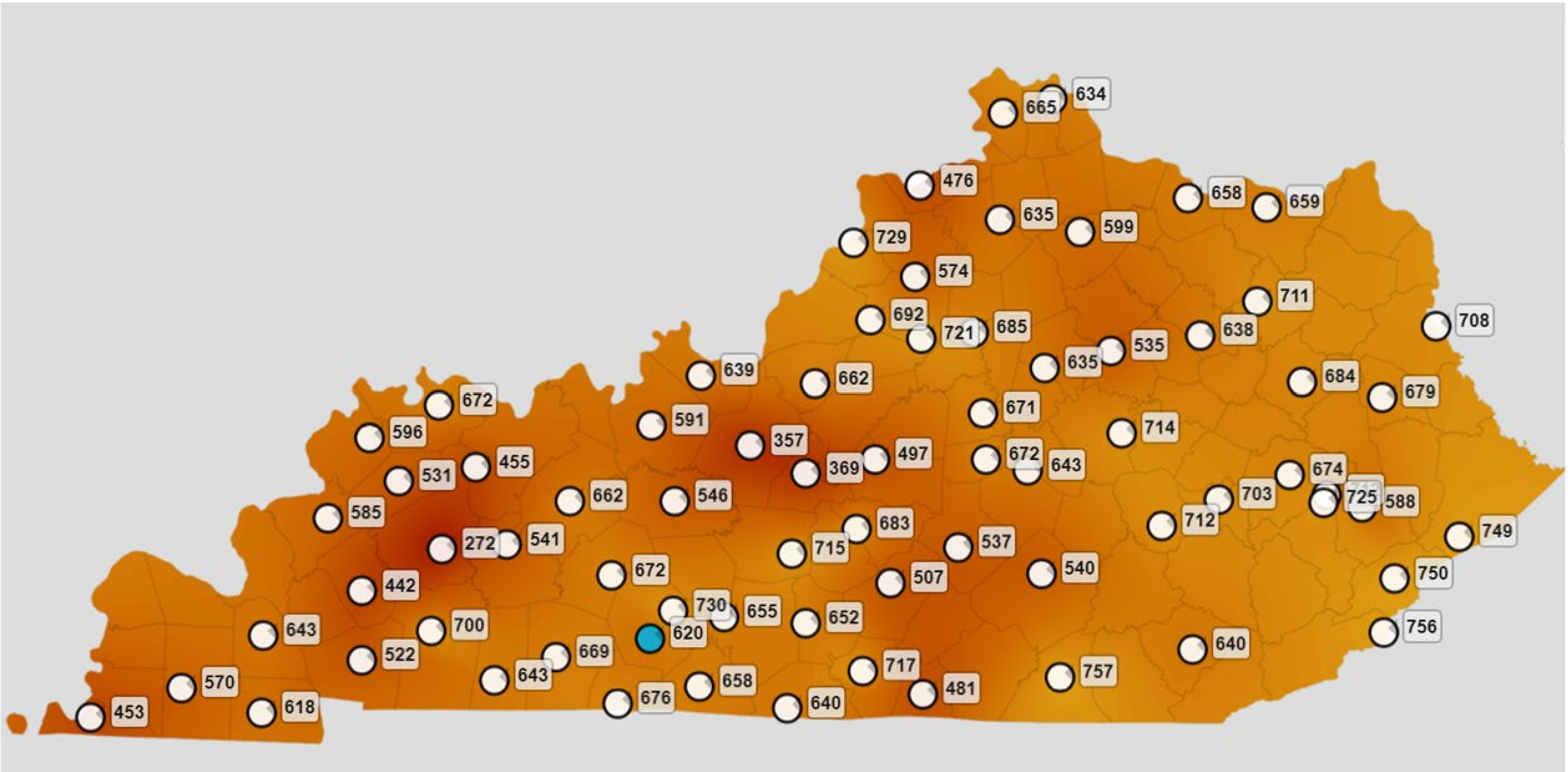
- **For ≤ 500 megawatts (MW) of solar**, the existing LG&E and KU generation portfolio—without operational changes—can regulate output to meet demand with negligible imbalances.
- **Solar penetration between 500 and 1,000 MW** would require some minor changes to generation unit operation, dispatch, and unit commitments with minor costs for generation to match load in real time.
- **Solar penetration above 1,000 MW**—to prevent significant imbalances—would require changes to the existing generation portfolio, including the retirement of older coal-fired generating units and addition of more-agile natural gas combined cycle units. As coal units are replaced with combined cycle units, the solar hosting capacity limit will be higher than 1,000 MW.
- If solar capacity were properly dispersed across the transmission system, there are no indications that solar penetration of ≤1,000 MW would create transmission problems. However, individual transmission system components, lines and transformers, are most-sensitive at the Point of Interconnection (POI) and neighboring regions of the system; thus, a detailed power flow analysis and circuit study is required for each project.
- The option to curtail surplus solar power, even at cost, is critical for increasing solar penetration.
- The addition of natural gas combined cycle units will increase the solar hosting capacity limit.
- The addition of lithium-ion energy storage, which respond instantaneously, can mitigate problems caused by solar intermittency including short-term generation imbalances, and transmission support with auto frequency-watt and autonomous volt-Var functionality.
- Dynamic energy management systems could also mitigate imbalance and facilitate solar penetration.

# Solar Variation Data

# Active PV Interconnection Queue

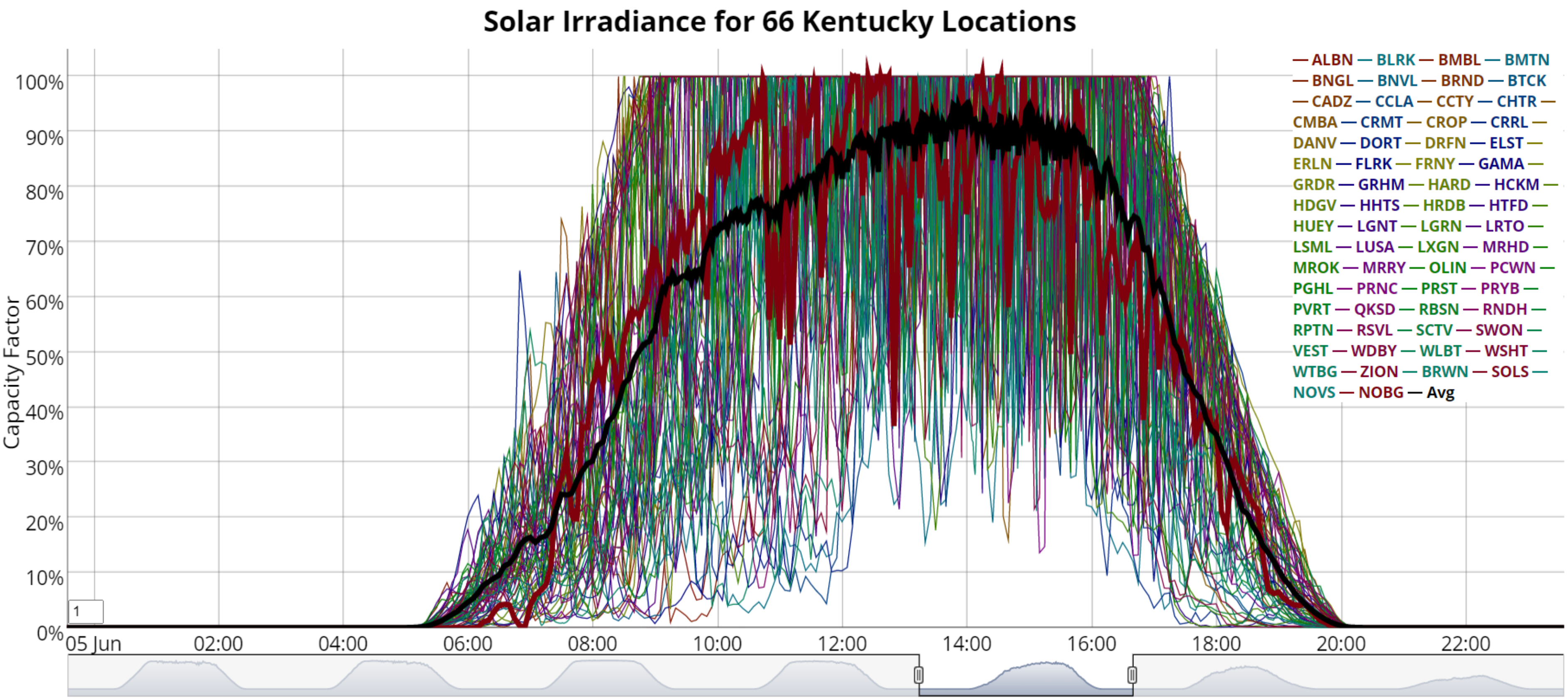


# New Solar Data for 67 Kentucky Stations




*Solar Irradiance Data from WKU KY Mesonet, NOAA, and LG&E and KU*

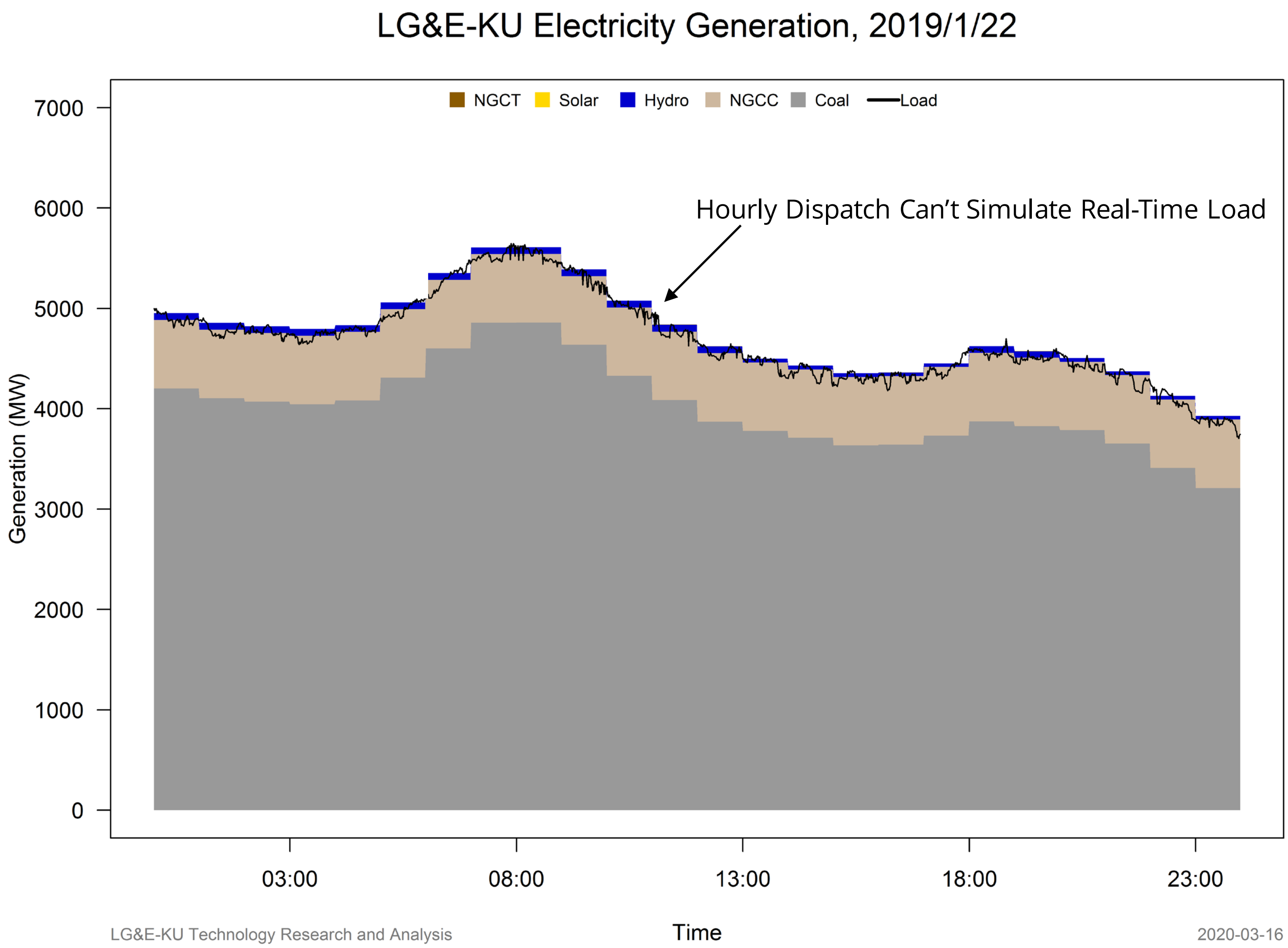
# Interactive Data for 67 Kentucky Stations



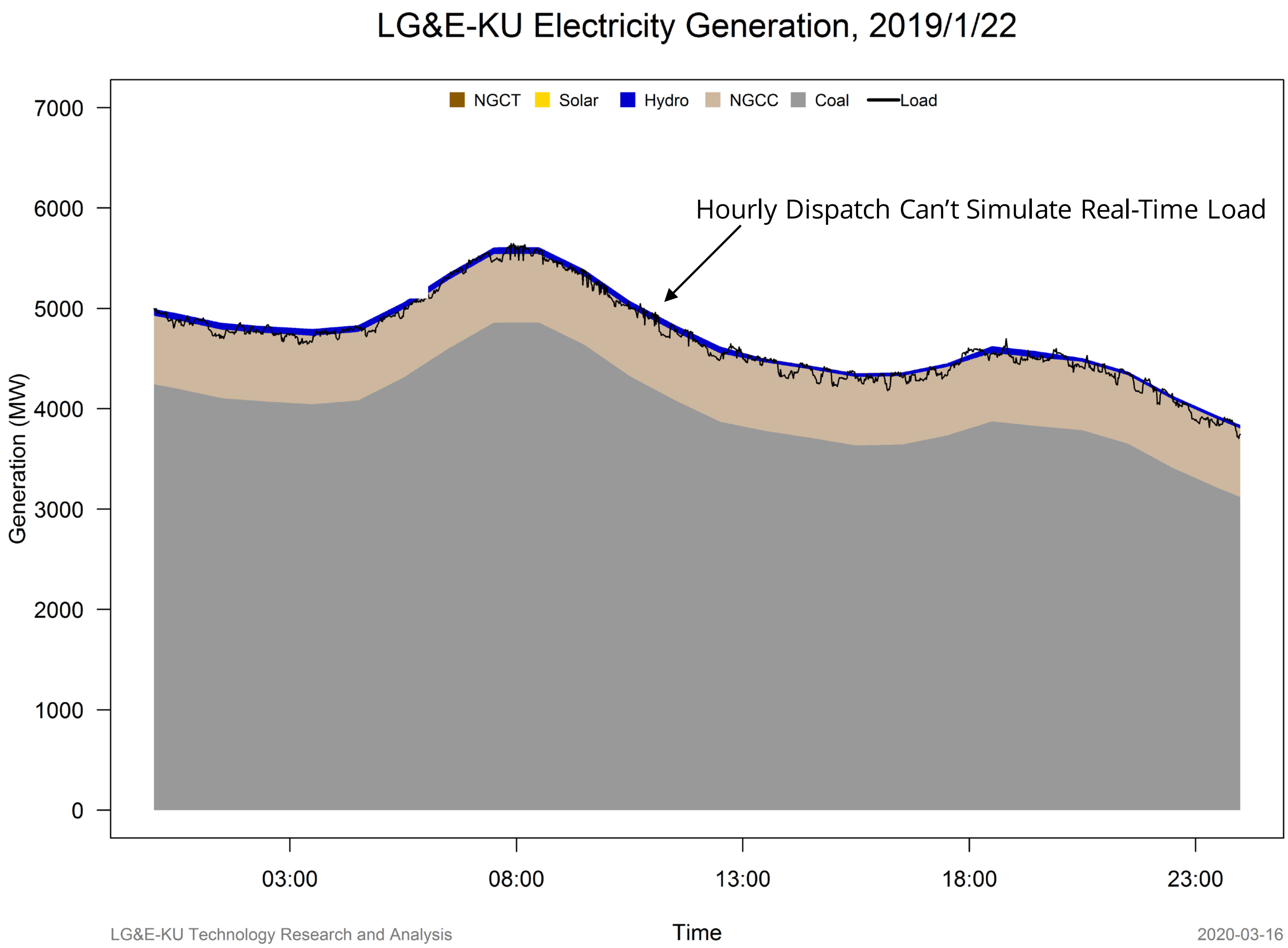

Open Interactive Data: https://teams.sp.lgeenergy.int/sites/RD/Plots/KY_Solar_Dash.html

# Generation Impacts

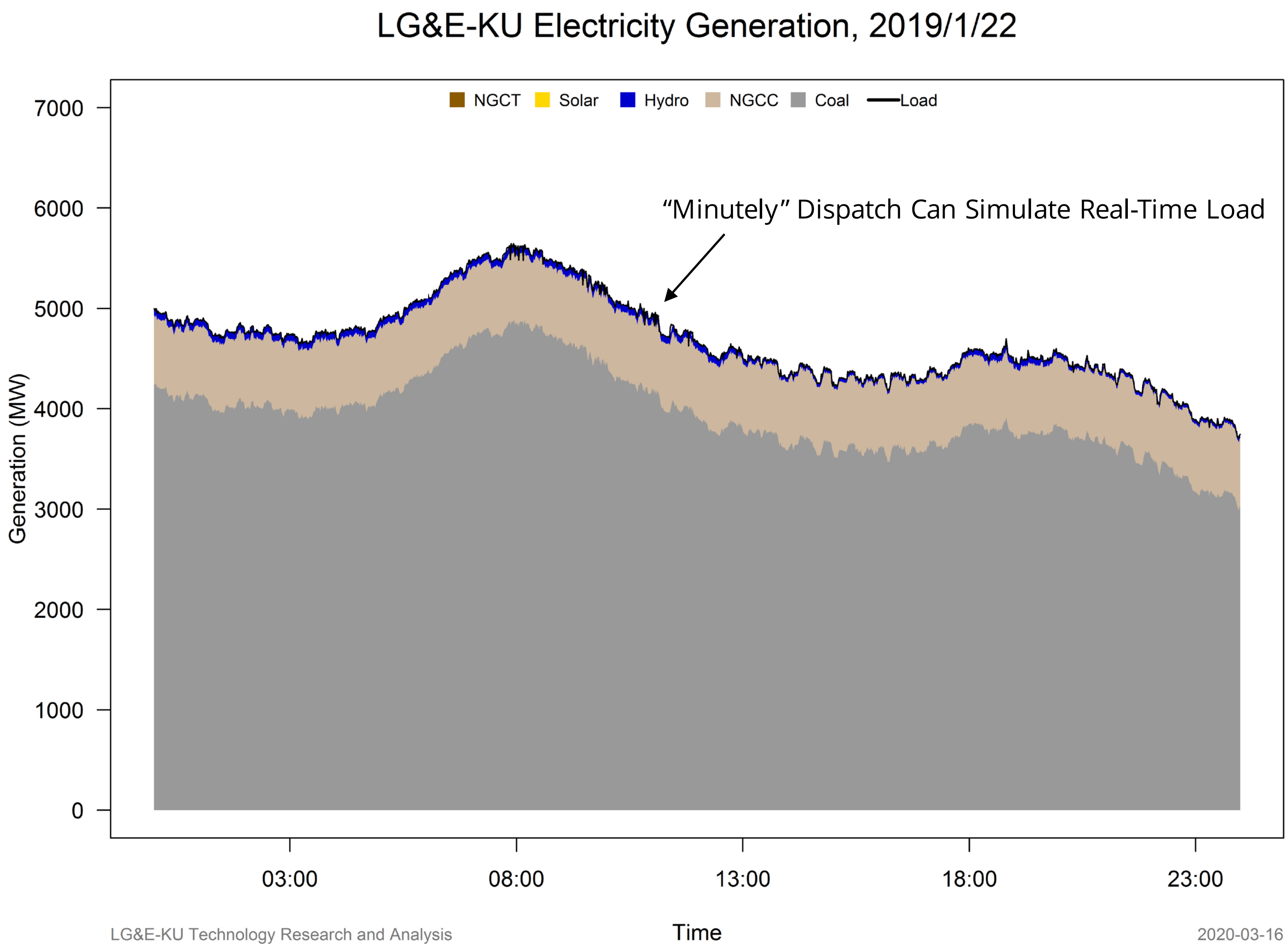
# Hourly Dispatch by Fuel in Prosym



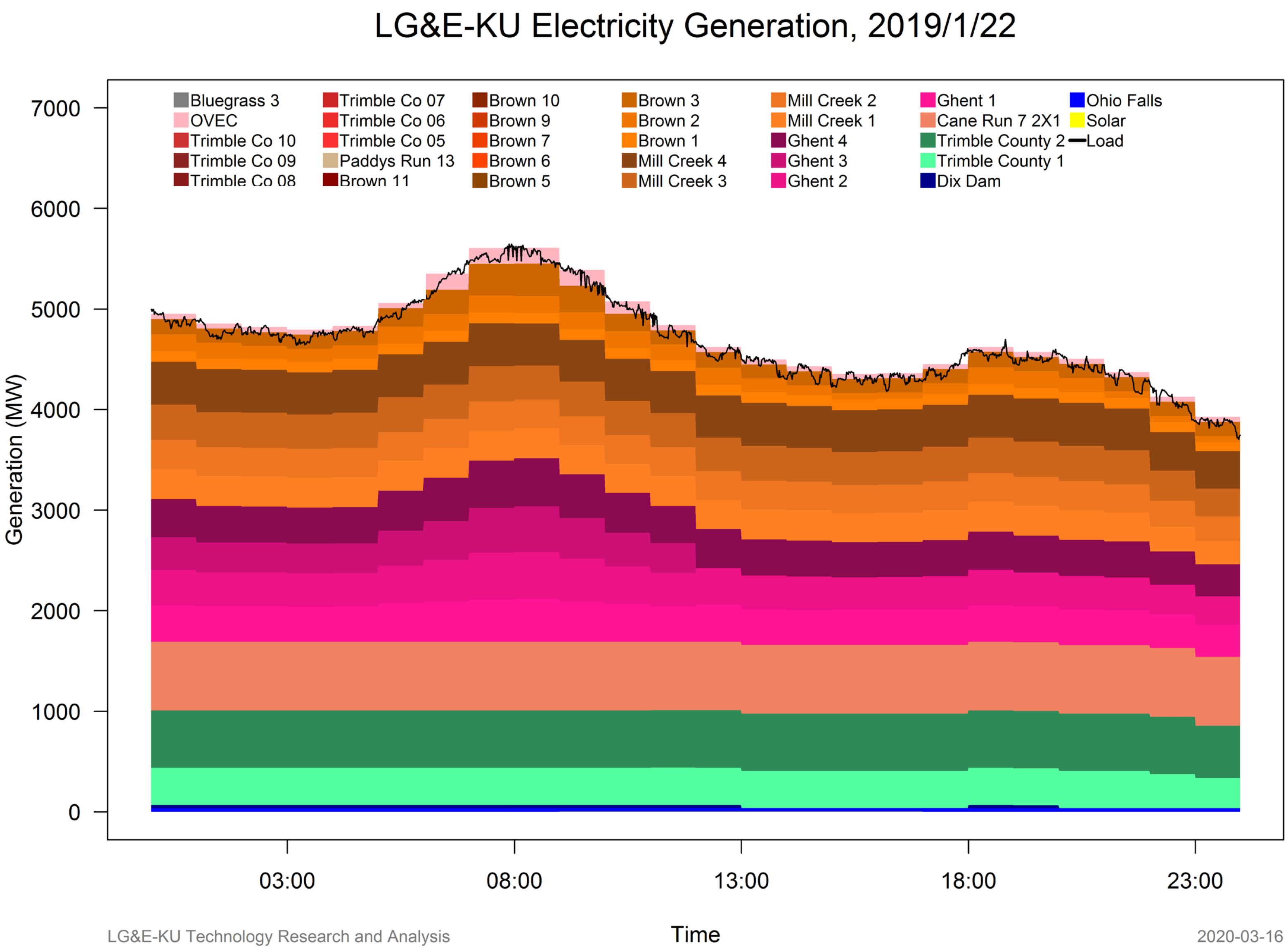
# Hourly Dispatch by Fuel in Prosym - Interpolated



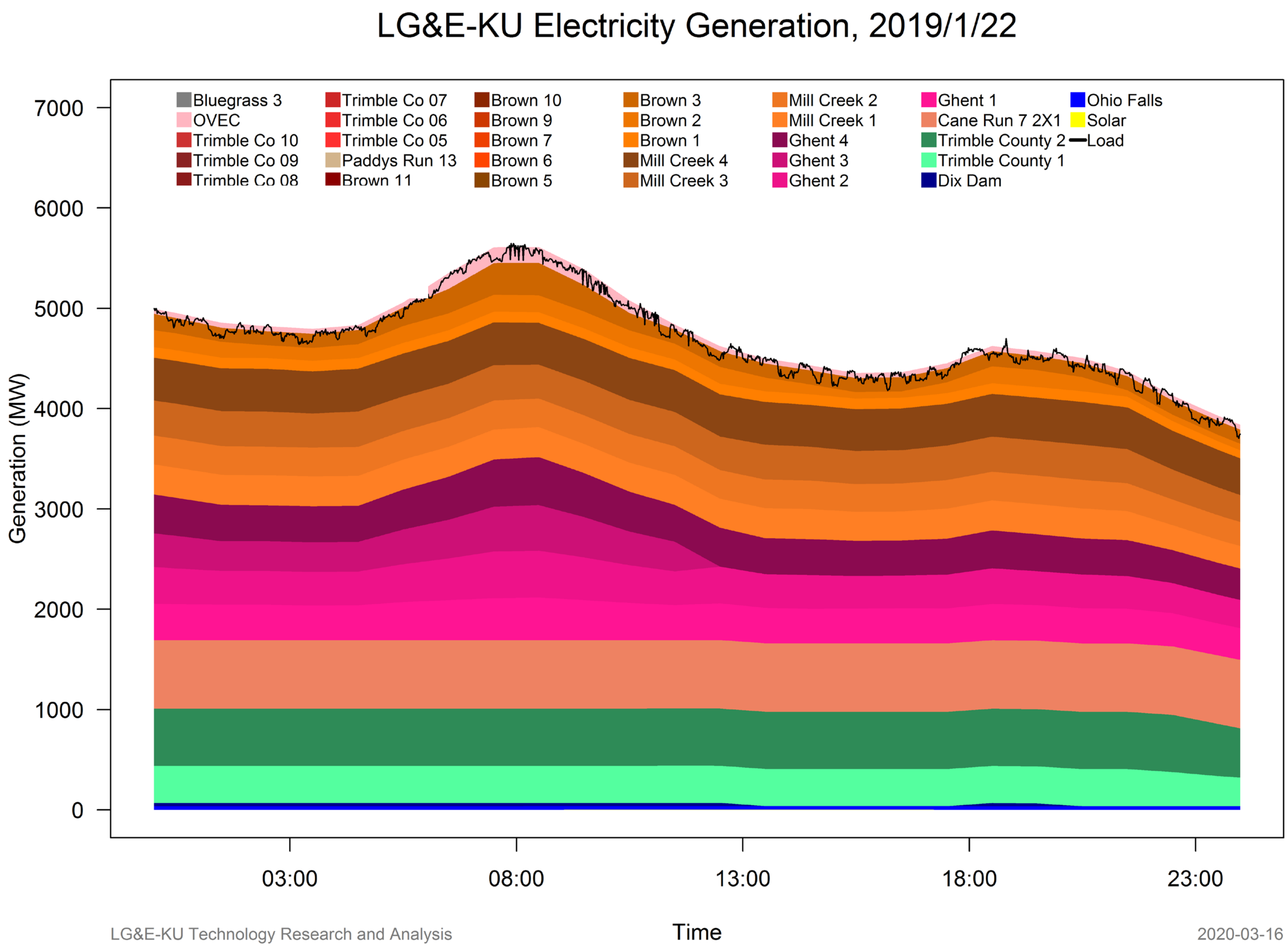
# New "Minutely" Dispatch by Fuel



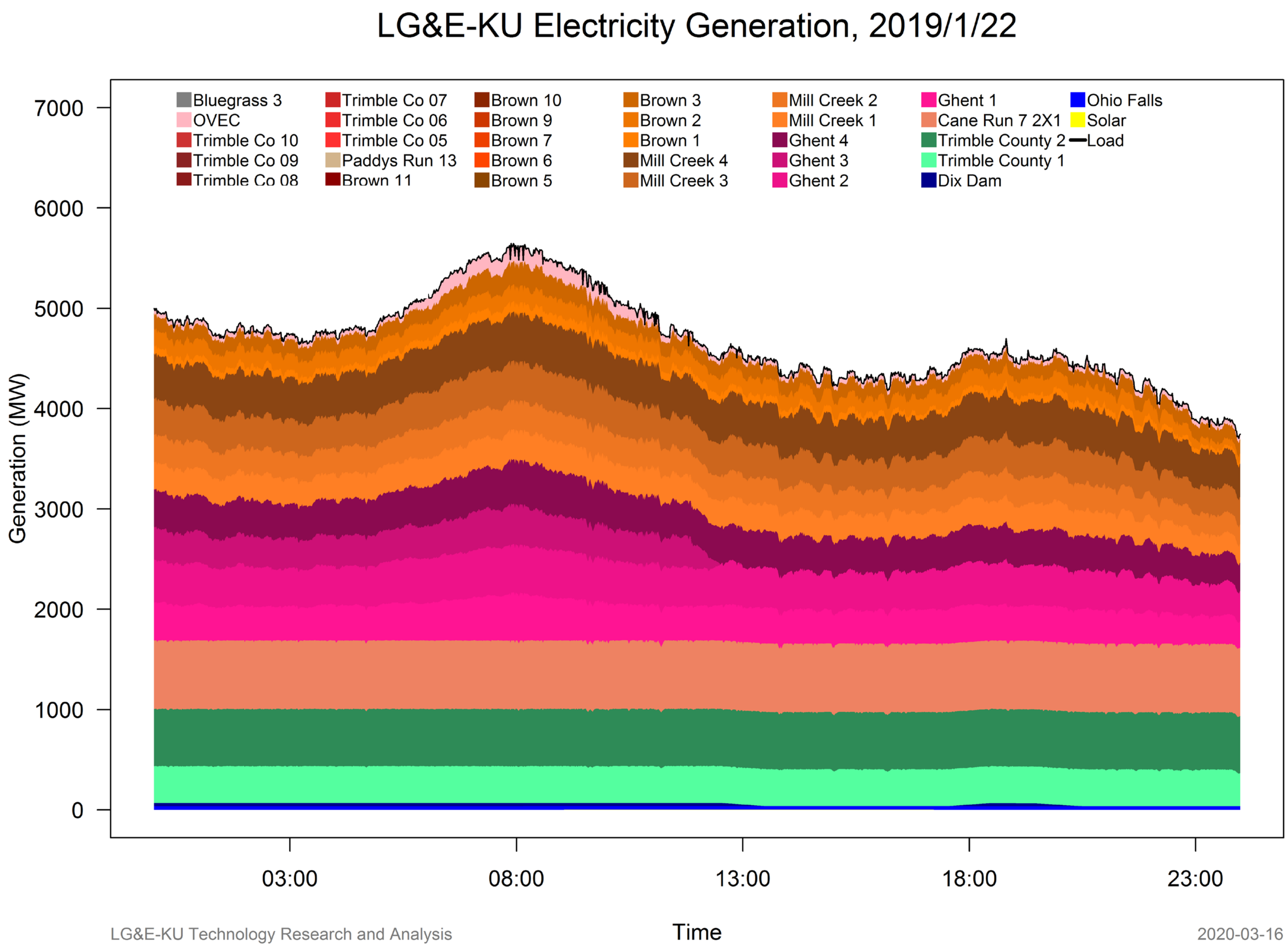
# Hourly Dispatch by Unit in Prosym



# Hourly Dispatch by Unit in Prosym - Interpolated



# "Minutely" Dispatch by Unit



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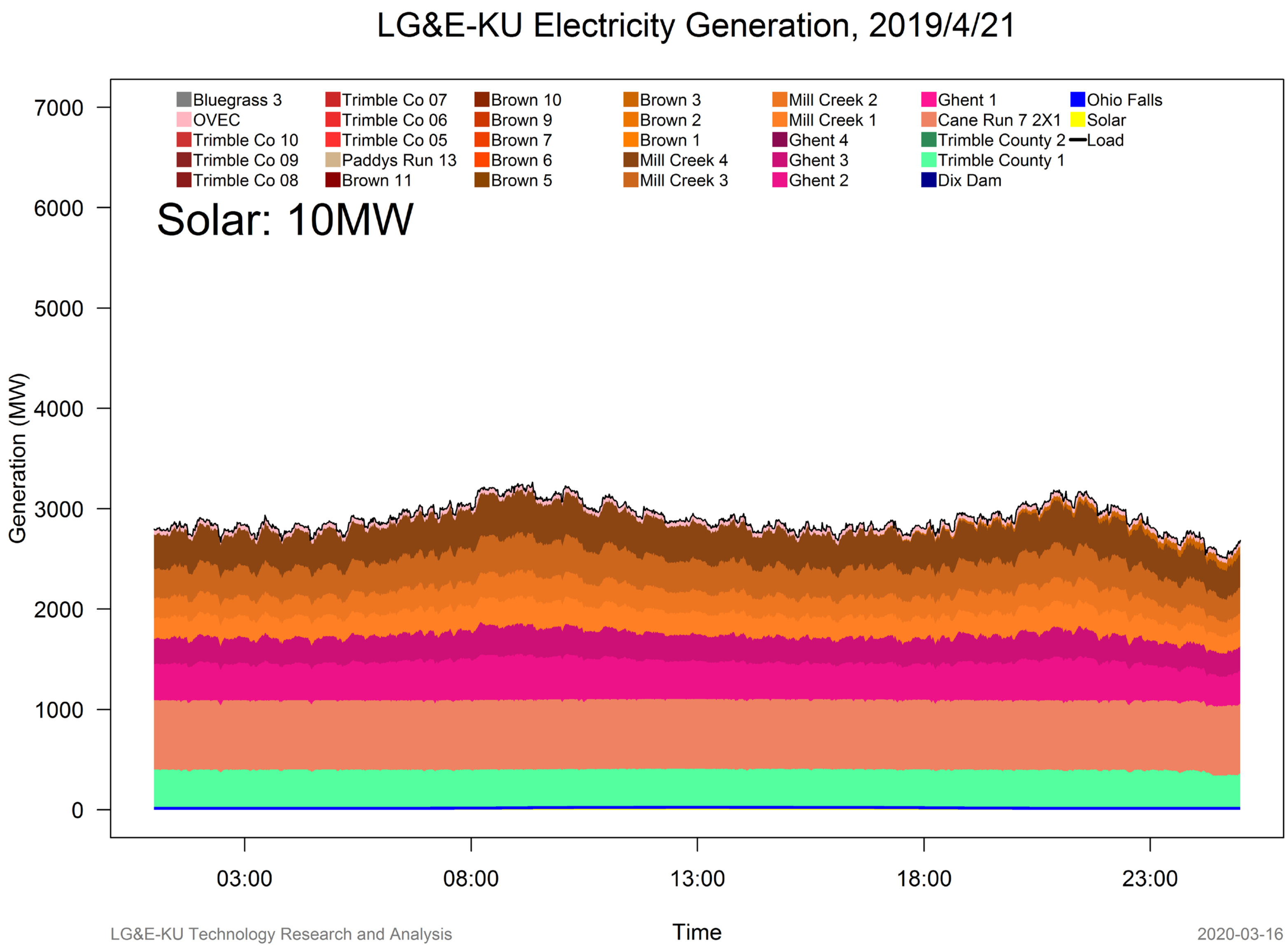
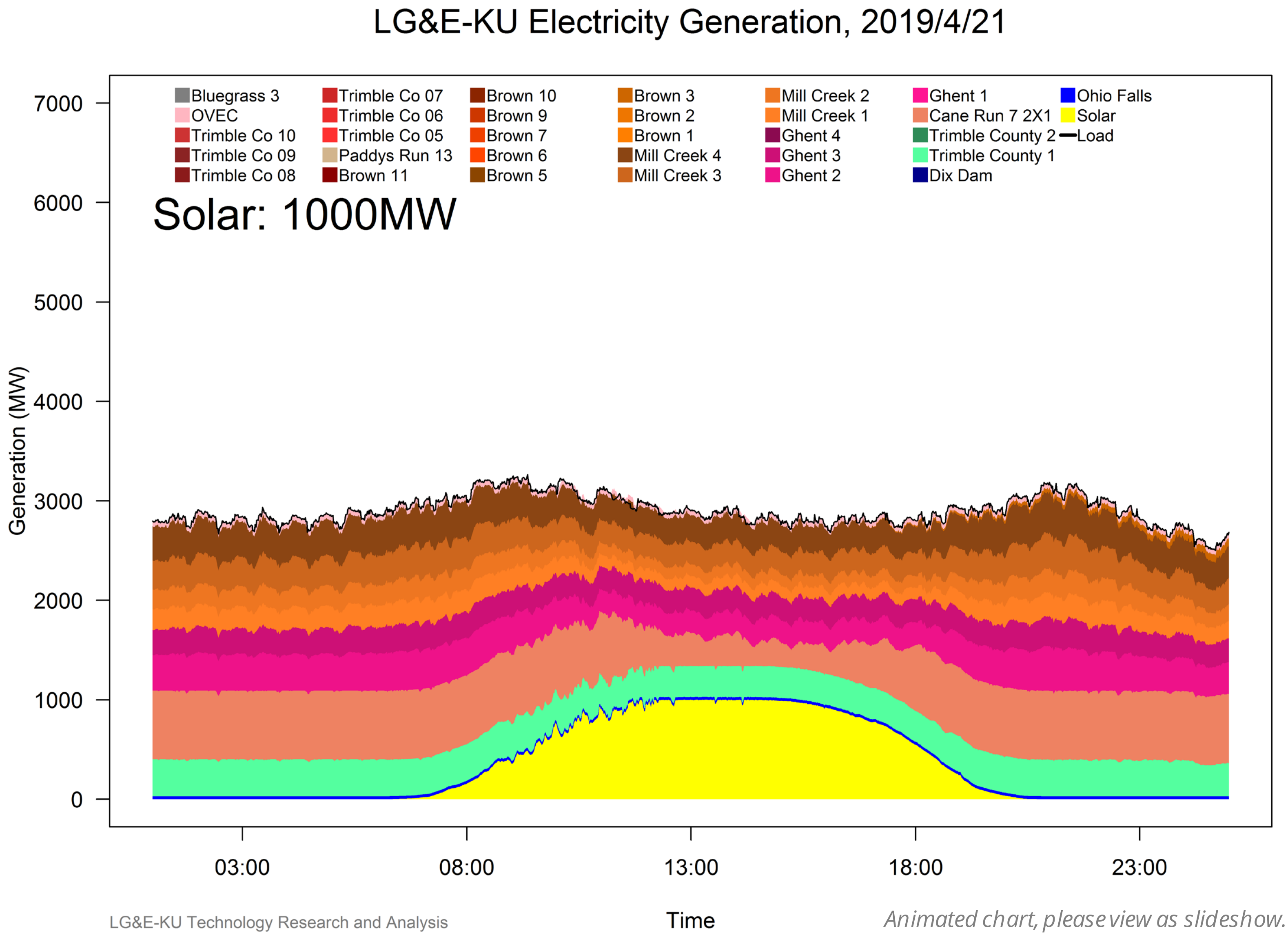
# Example Solar Impact by Unit – April – 10 MW Solar

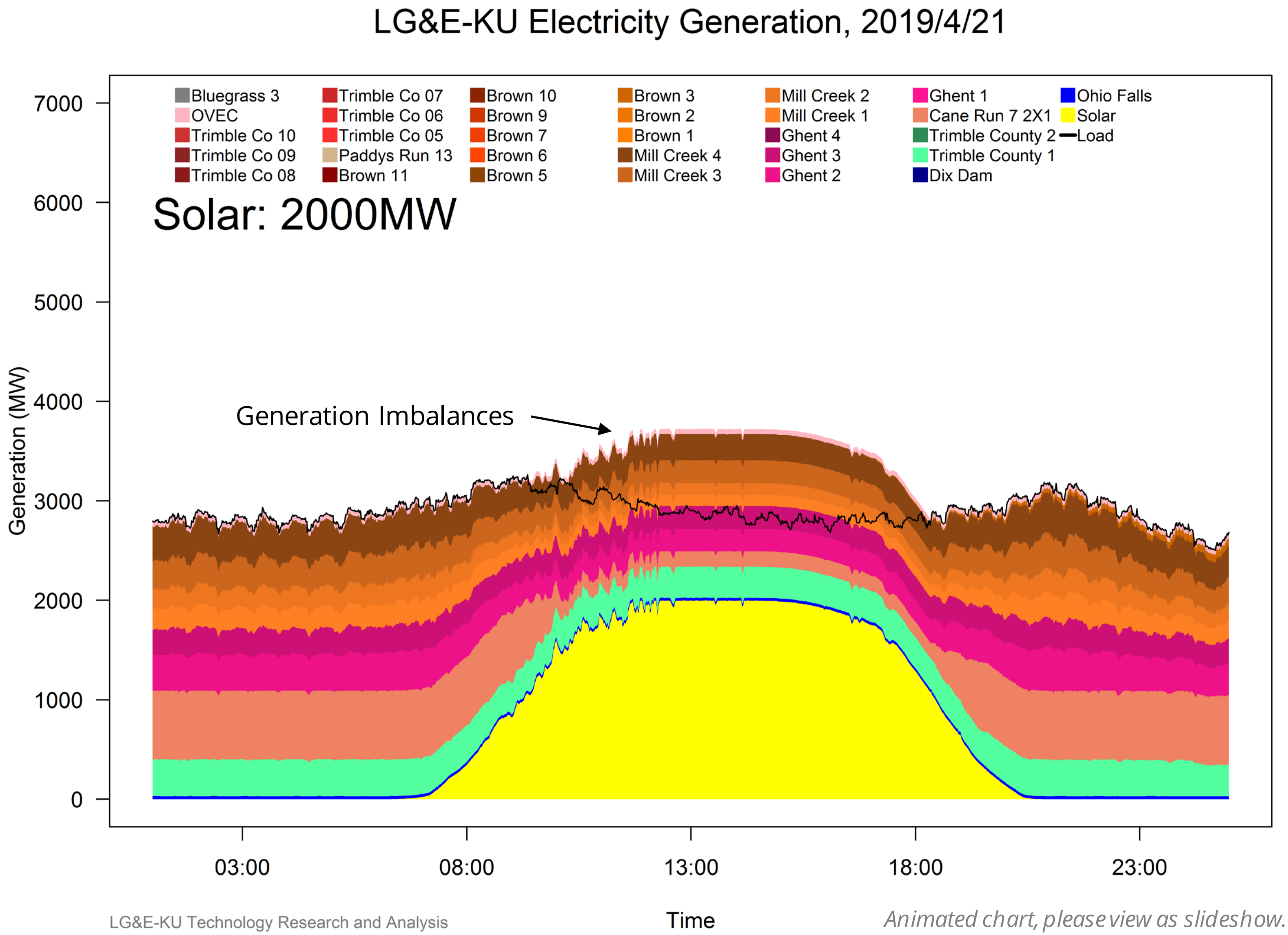


# Example Solar Impact by Unit – April – 1000 MW Solar




*Animated chart, please view as slideshow.*

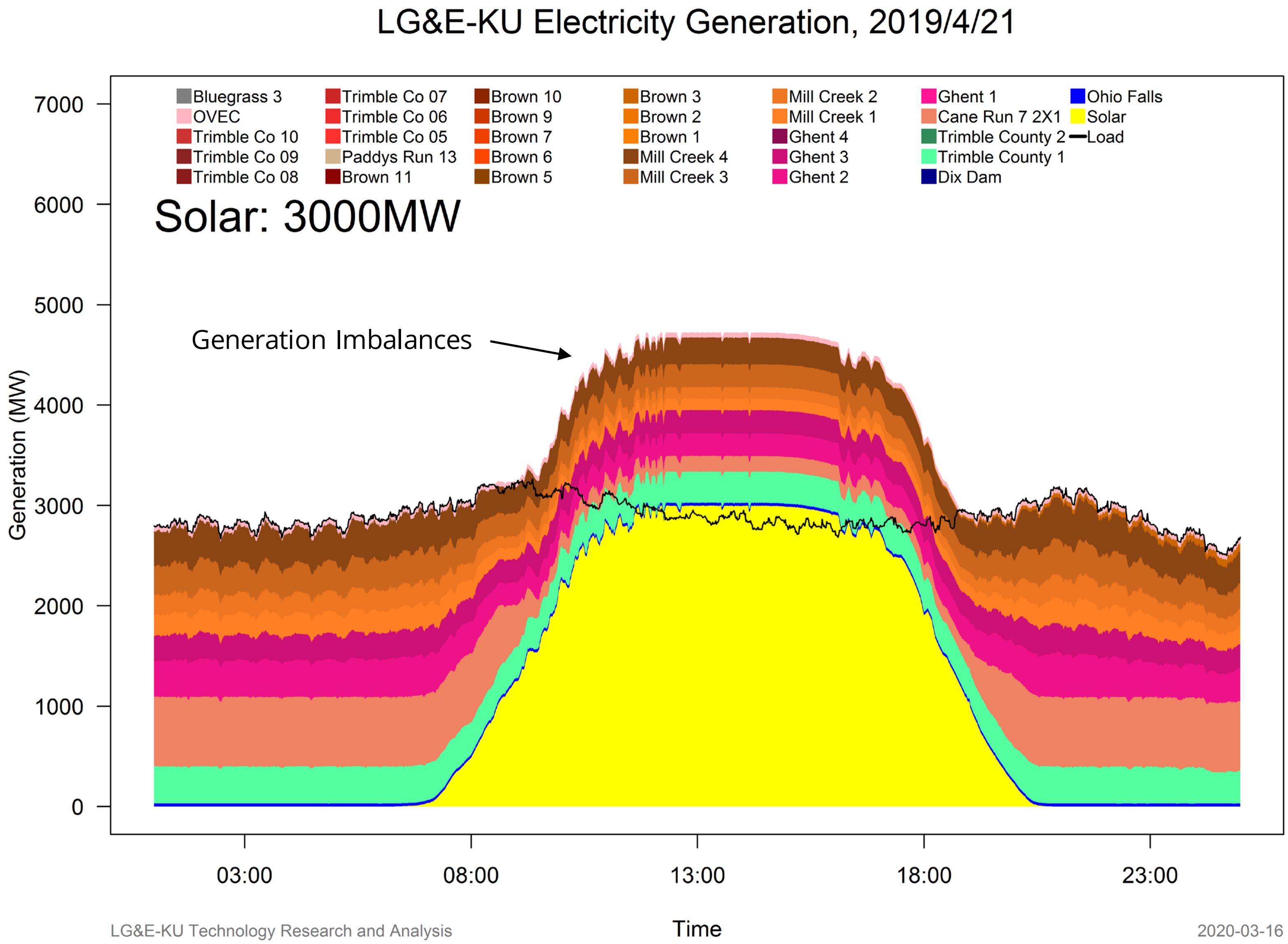
# Example Solar Impact by Unit – April – 2000 MW Solar



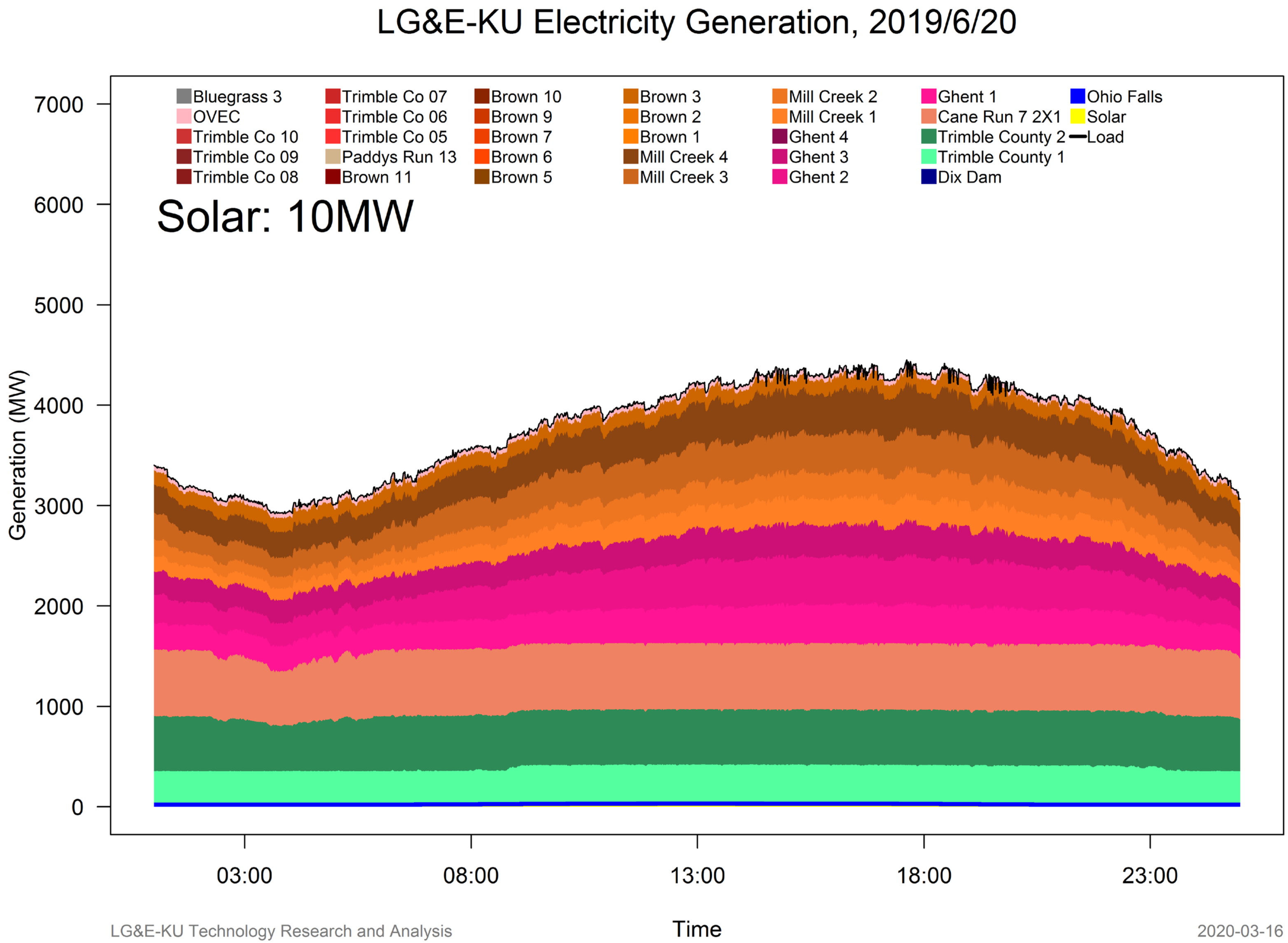

LG&E-KU Technology Research and Analysis

*Animated chart, please view as slideshow.*

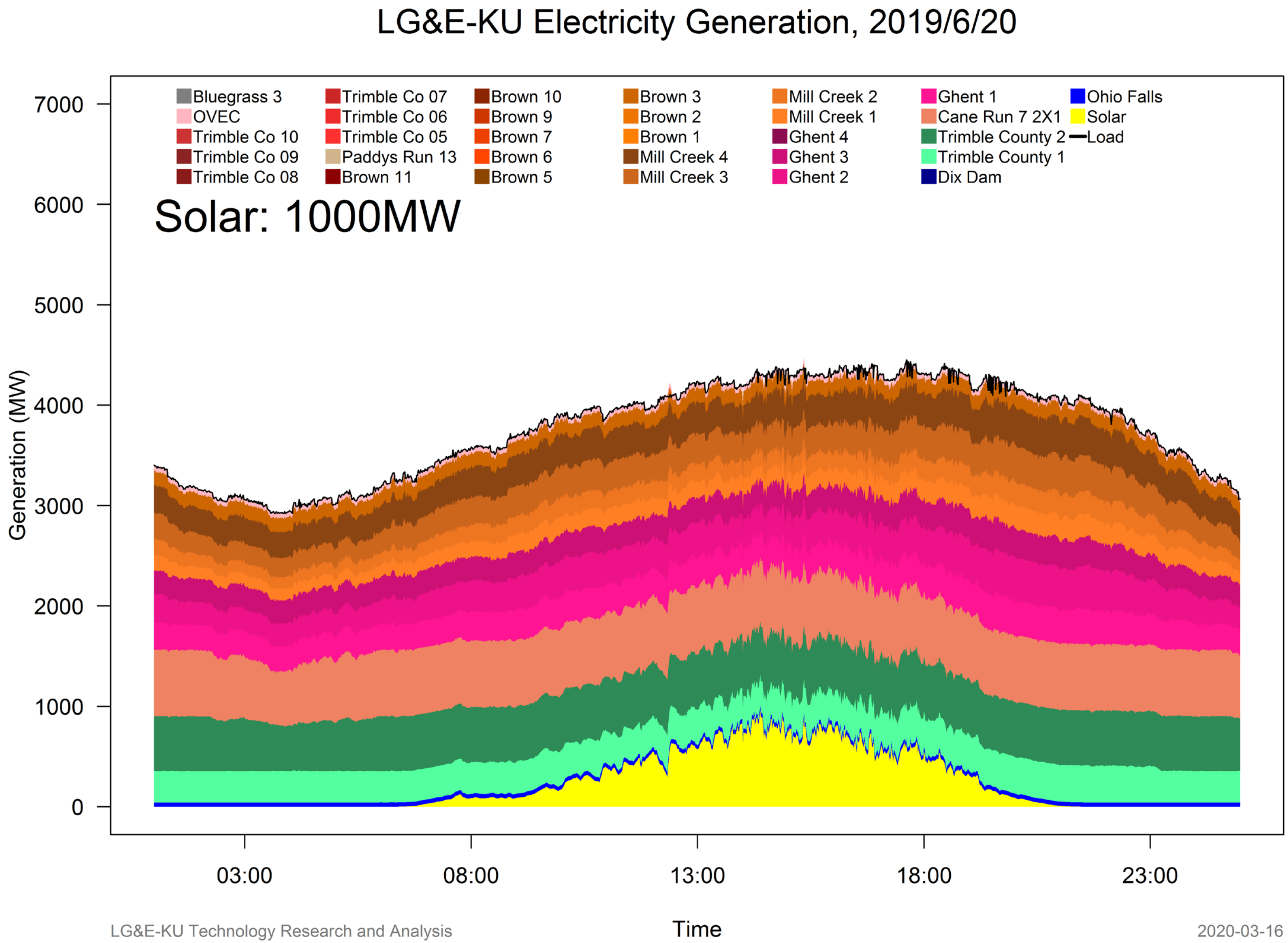
# Example Solar Impact by Unit – April – 3000 MW Solar



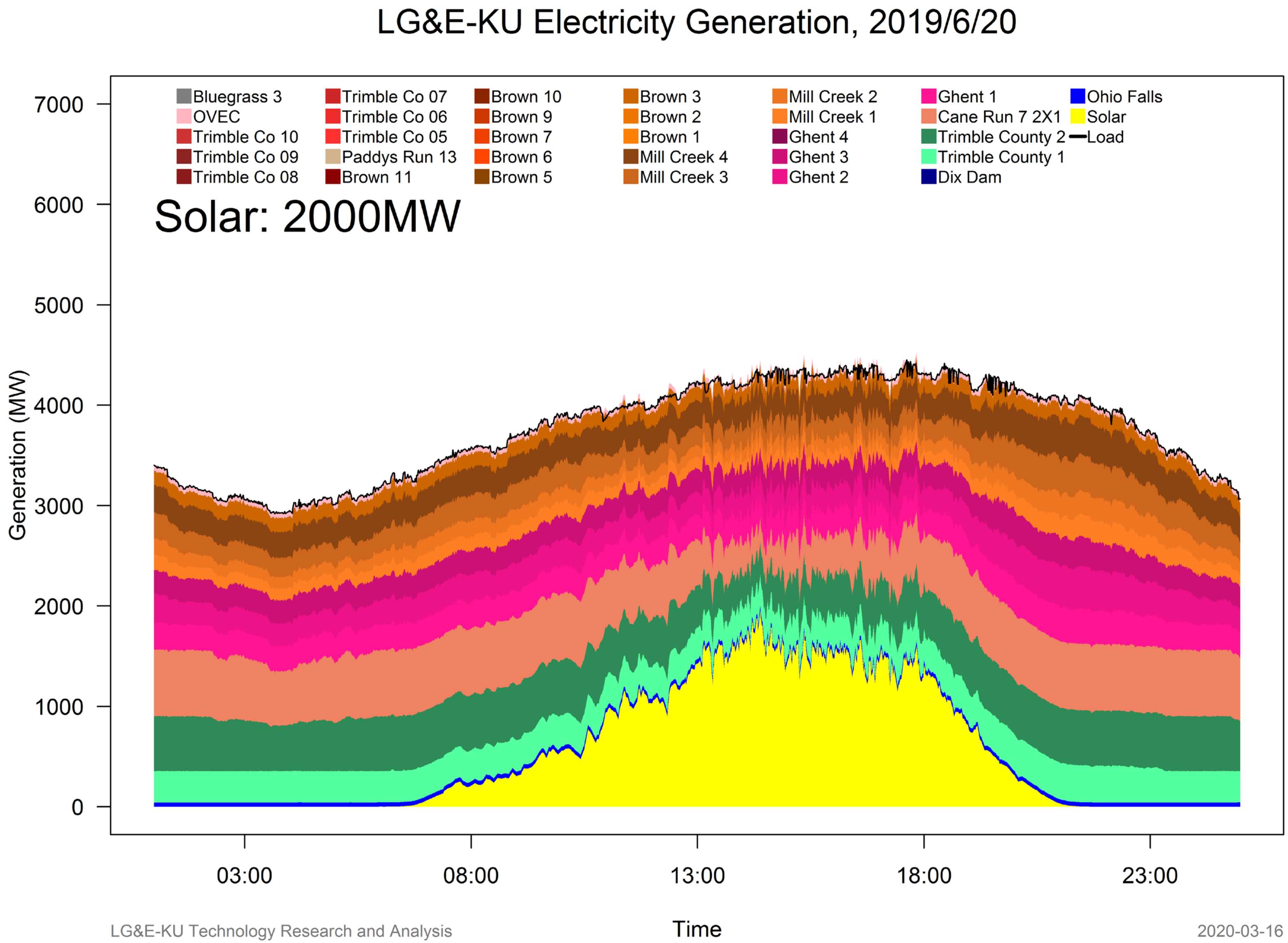
# Example Solar Impact by Unit – June – 100 MW Solar



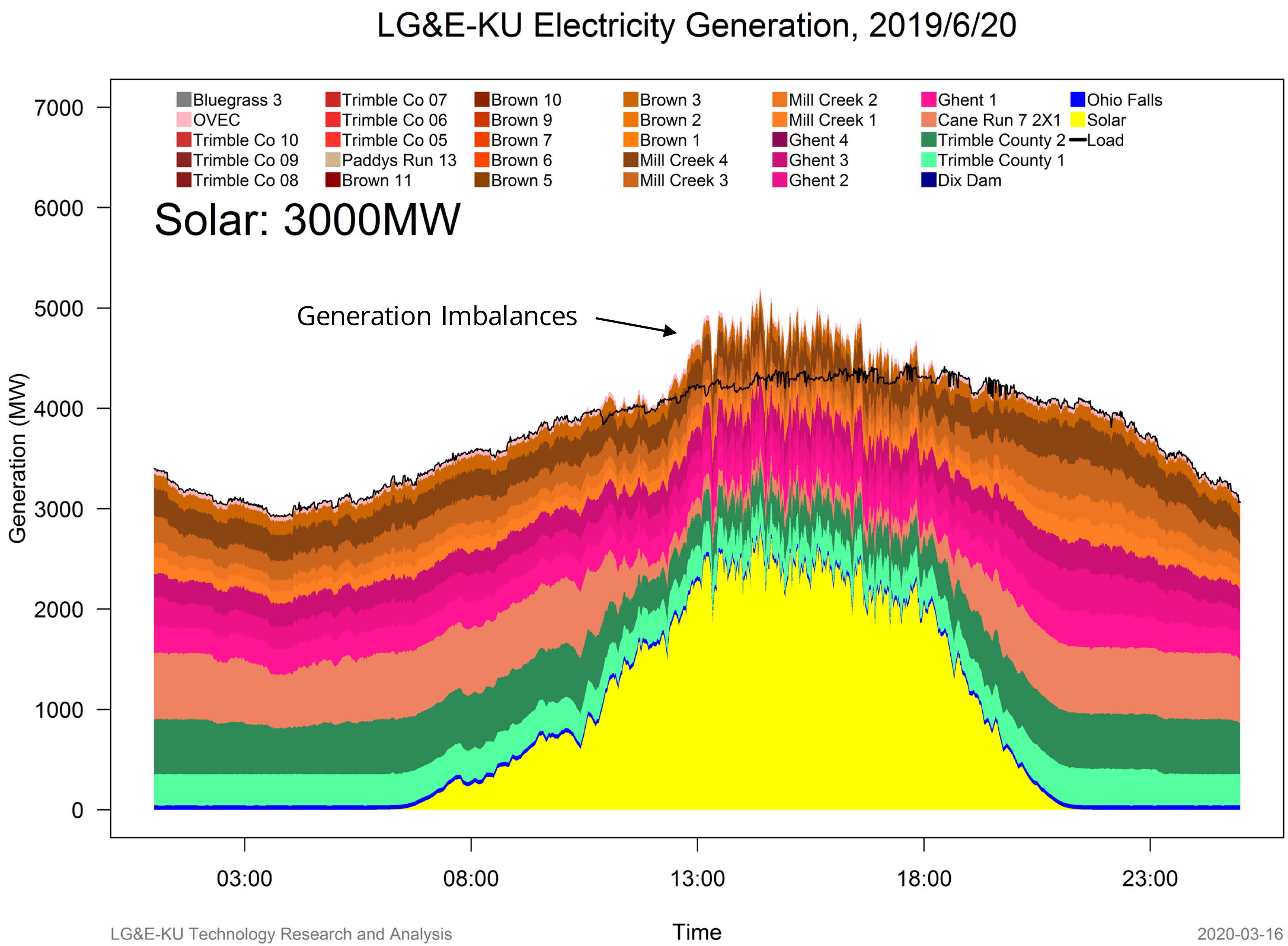
# Example Solar Impact by Unit – June – 1000 MW Solar



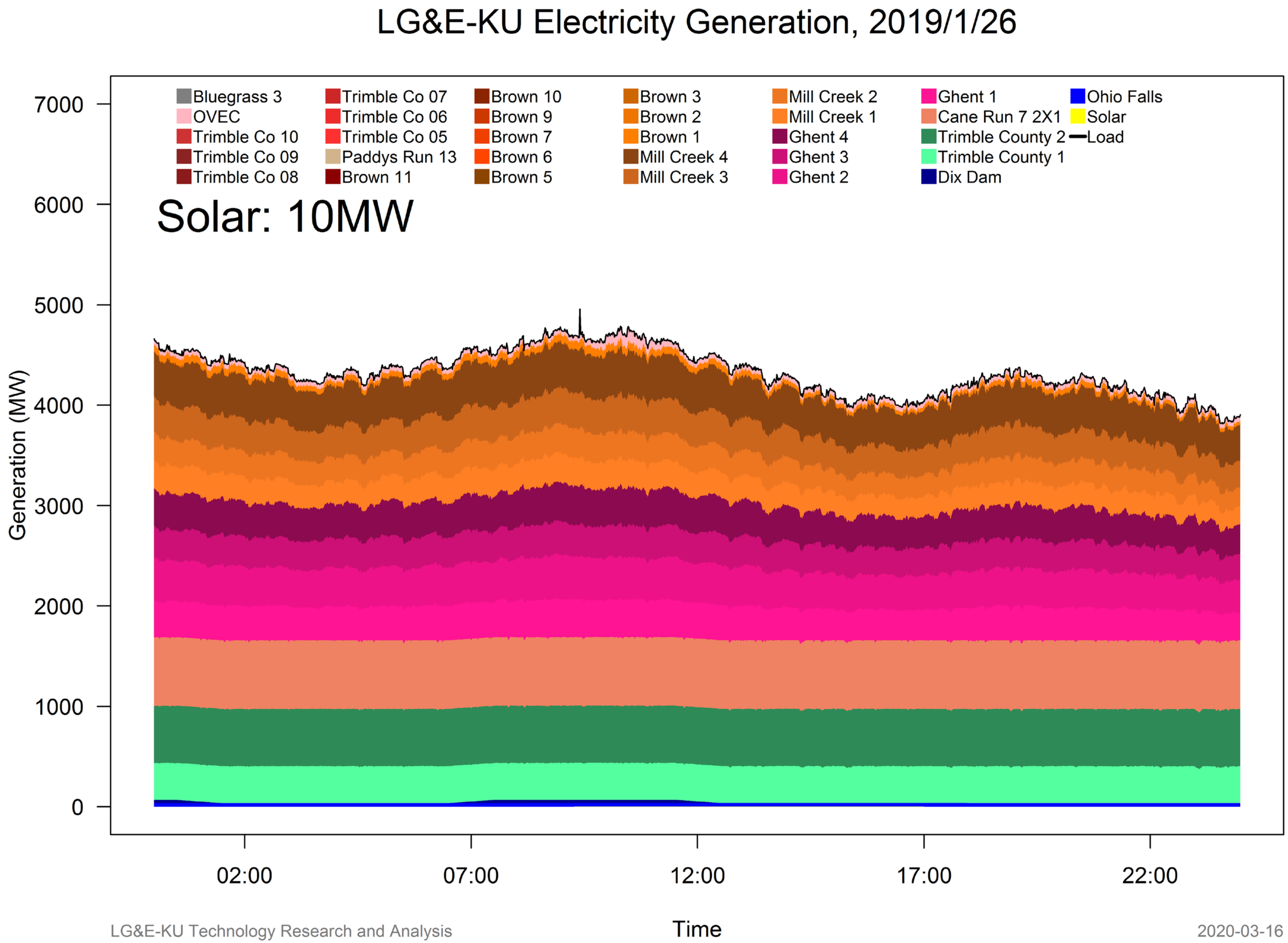
# Example Solar Impact by Unit – June – 2000 MW Solar



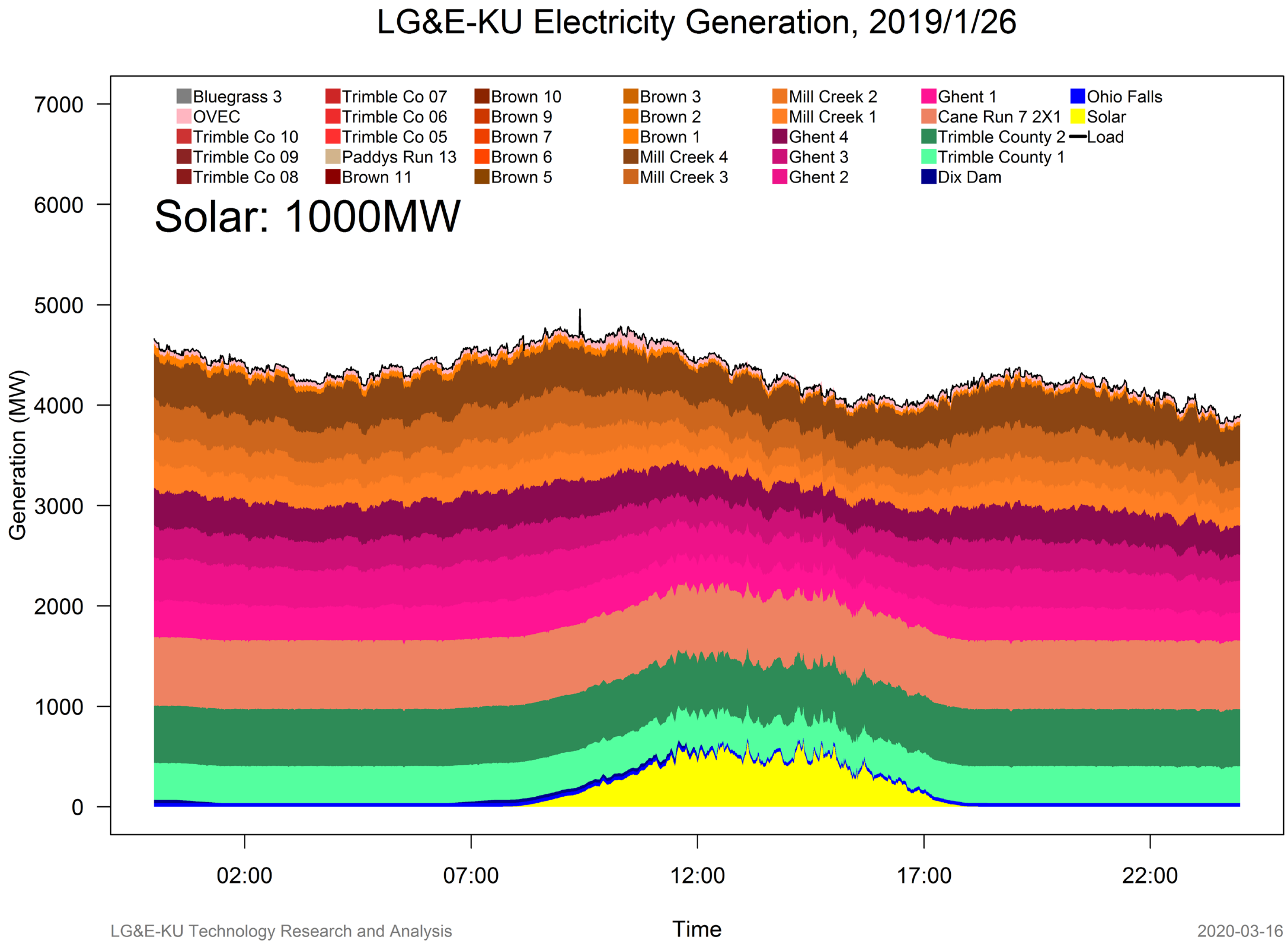
# Example Solar Impact by Unit – June – 3000 MW Solar



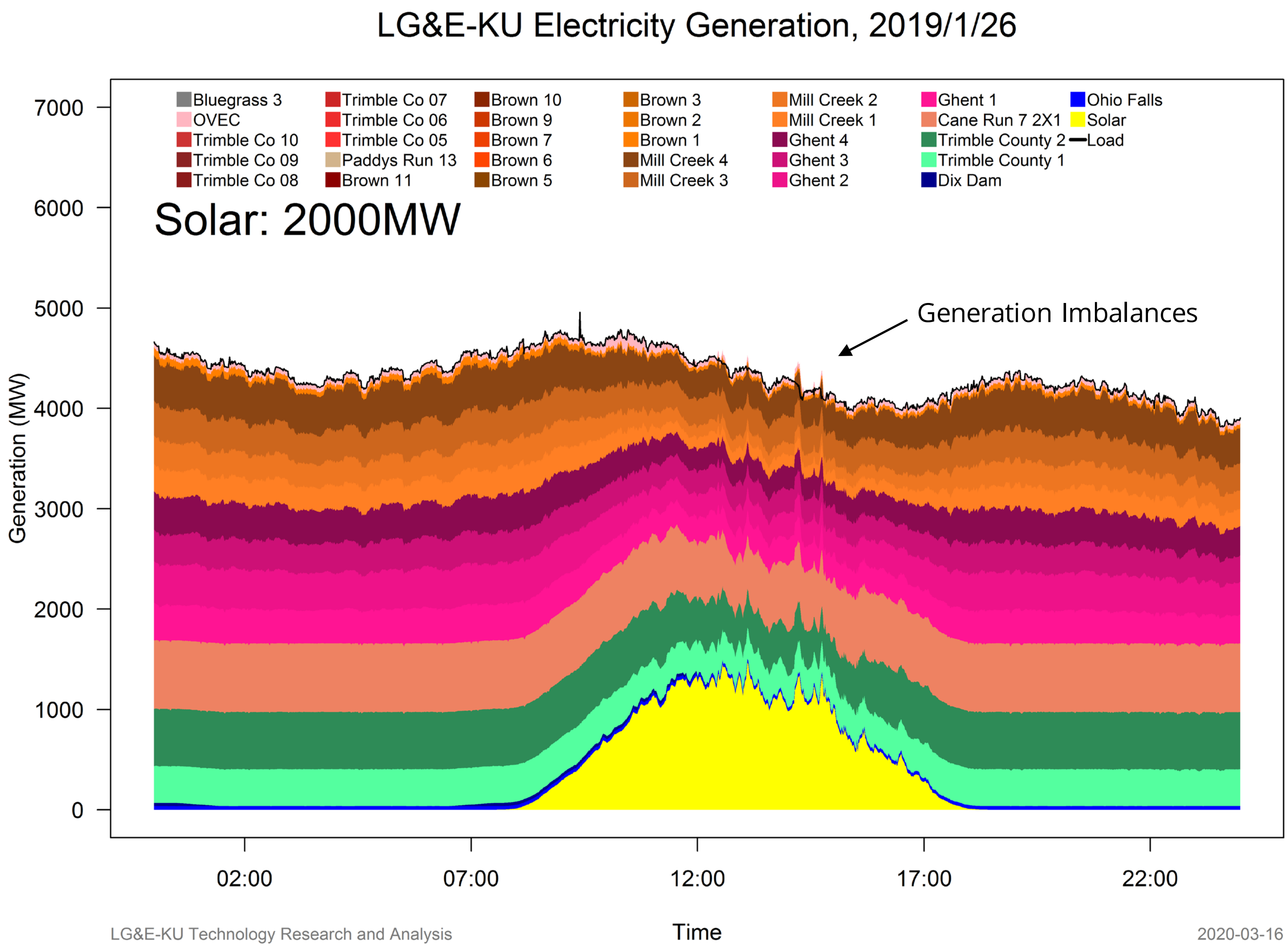
# Example Solar Impact by Unit – January – 100 MW



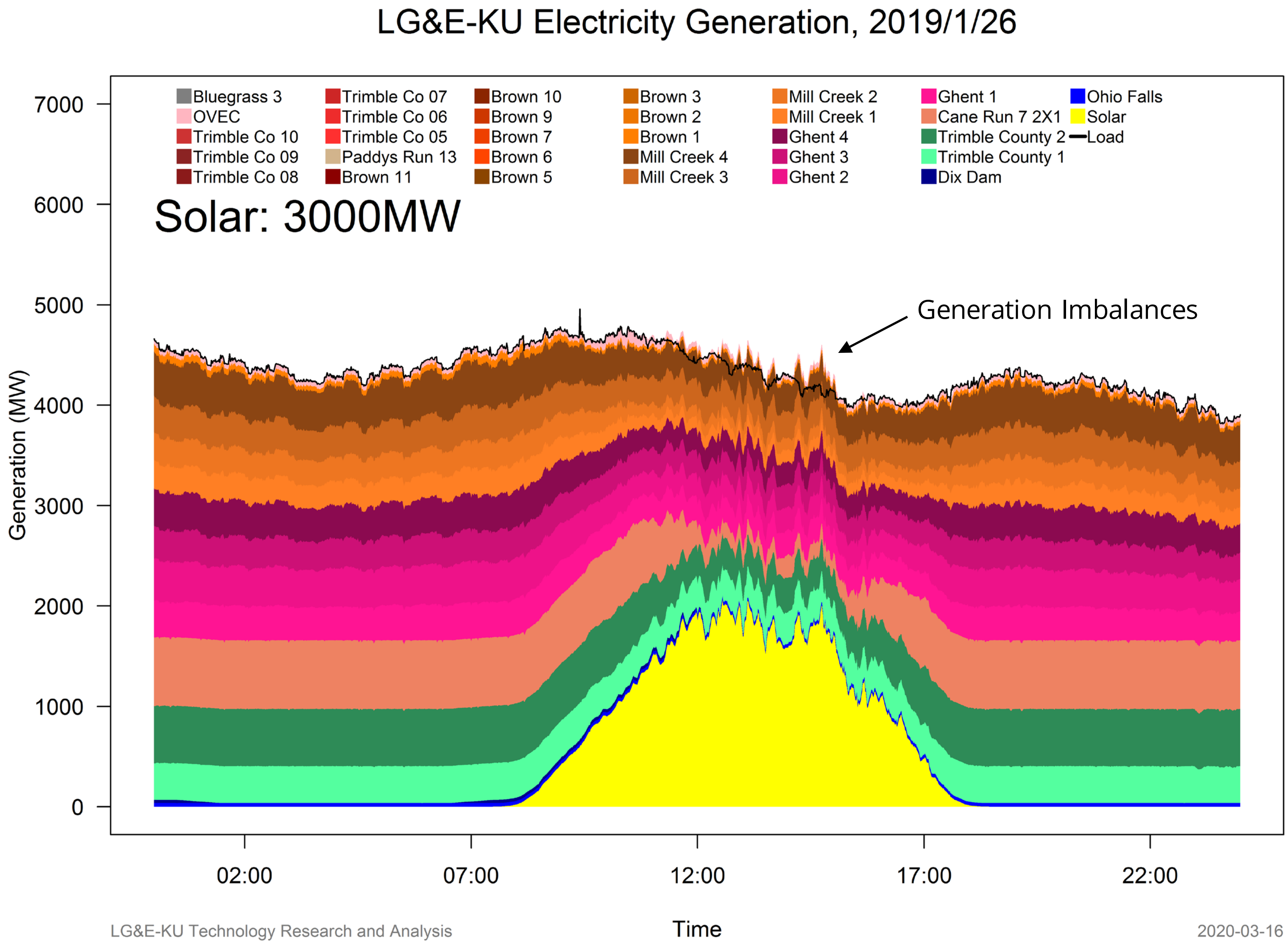
# Example Solar Impact by Unit – January – 1000 MW



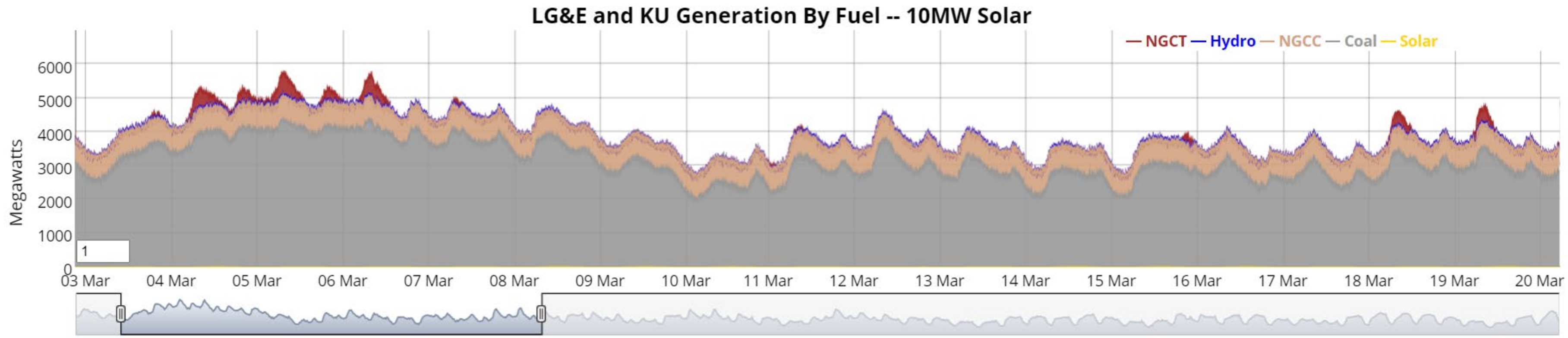
# Example Solar Impact by Unit – January – 2000 MW

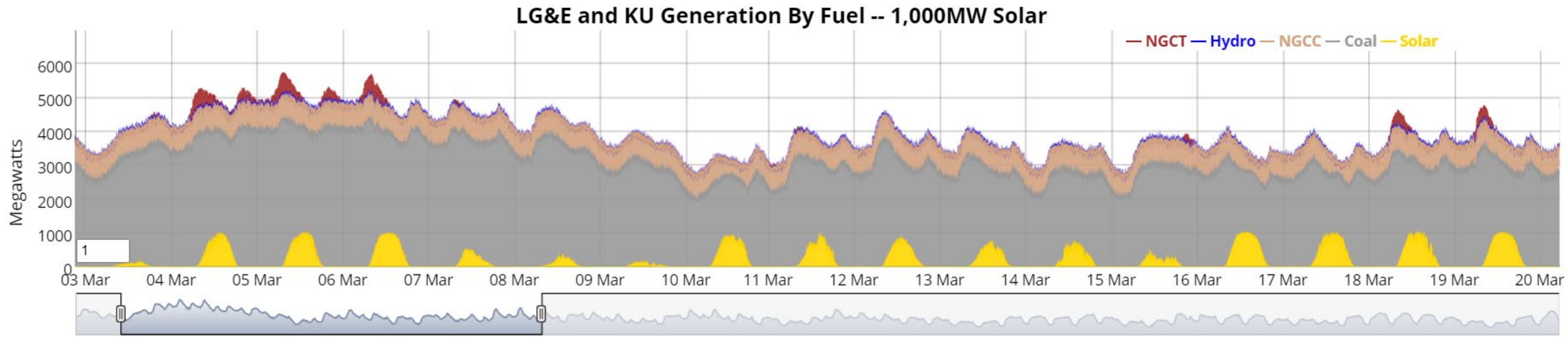


# Example Solar Impact by Unit – January – 3000 MW



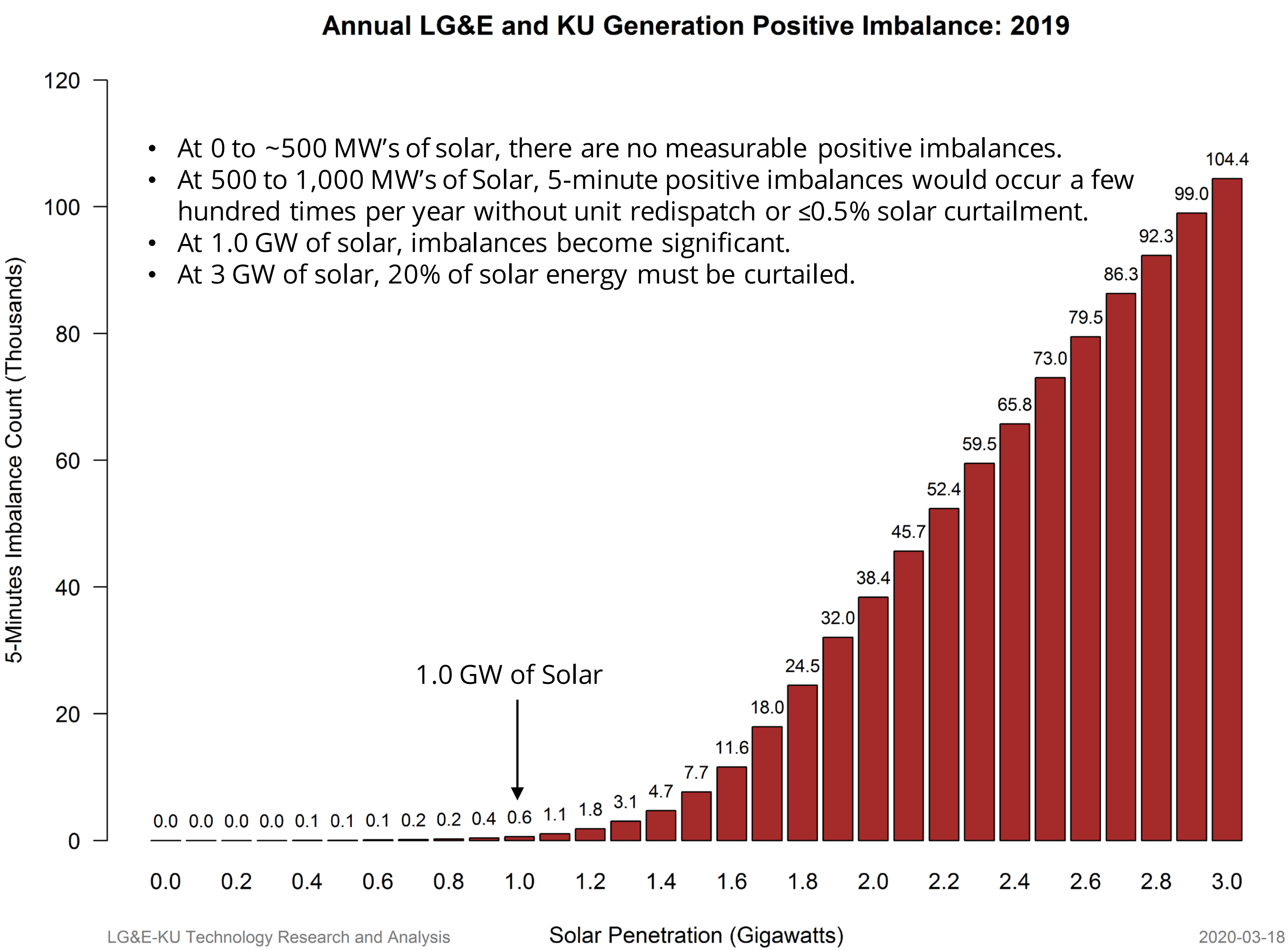
# Interactive Simulation Results



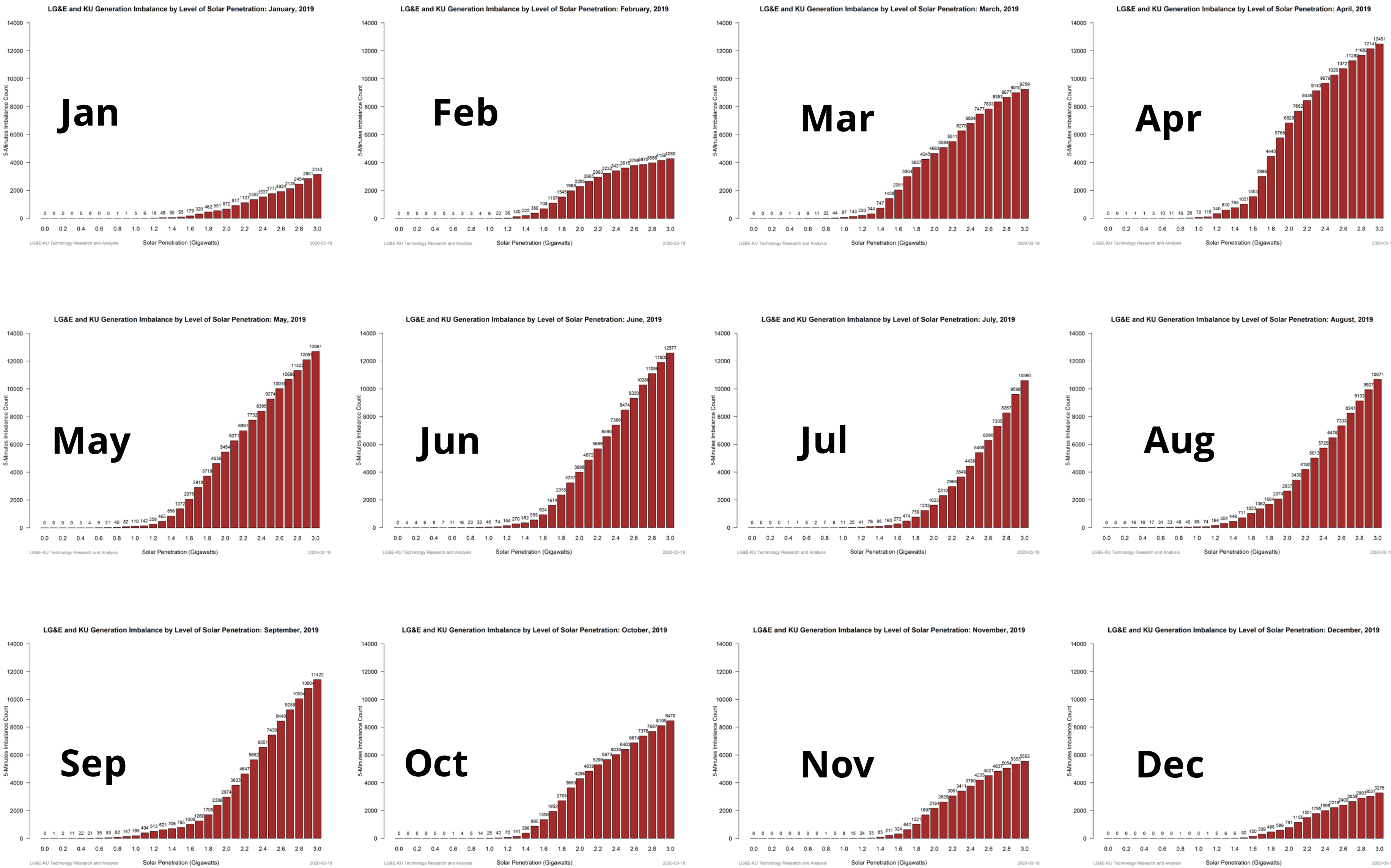




Open Interactive Data: https://teams.sp.lgeenergy.int/sites/rd/Plots/LKE_Dispatch.html

# Annual 5-Minute Imbalances by Solar Penetration



# Monthly 5-Minute Imbalances by Solar Penetration



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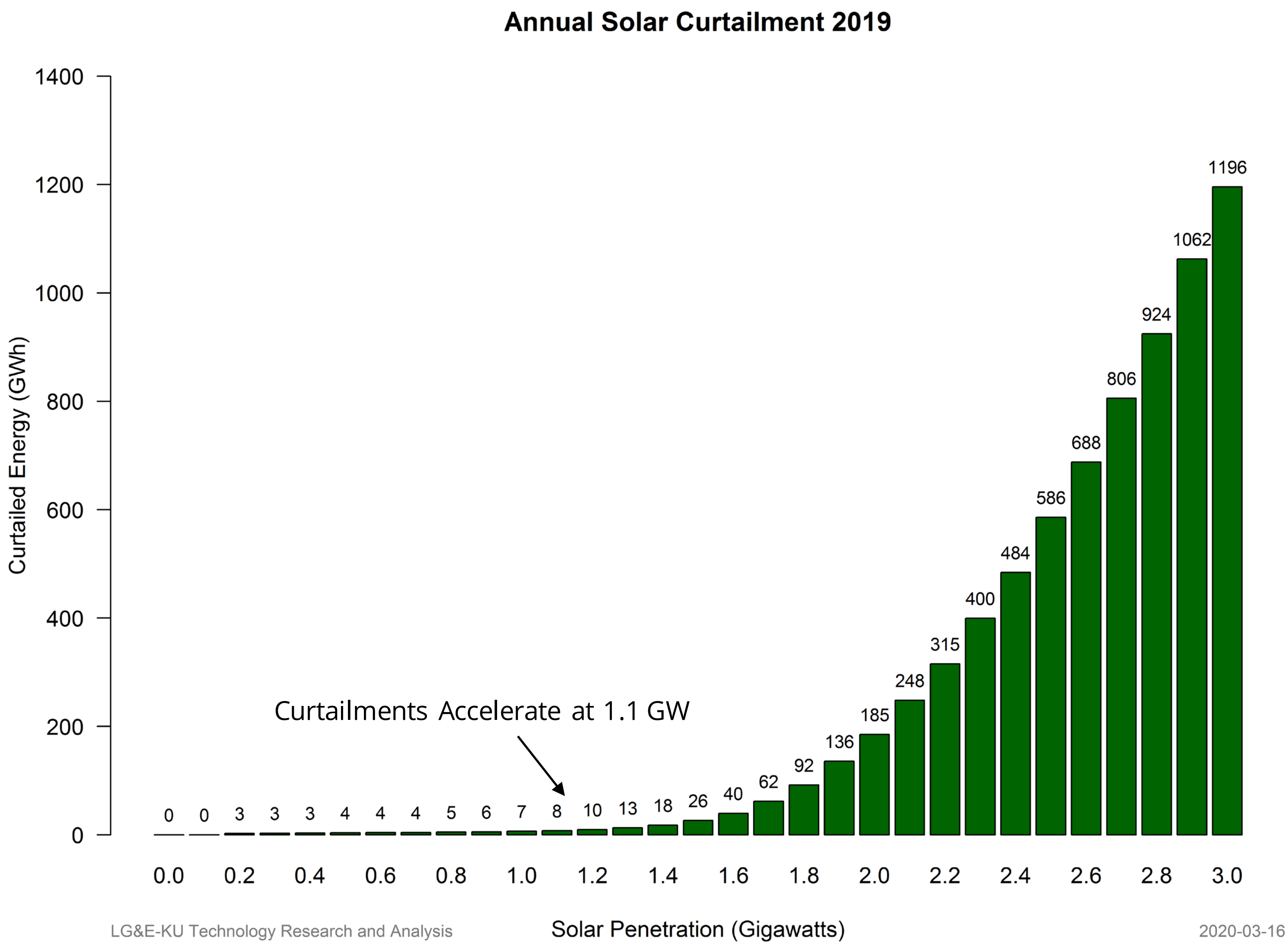
# Annual Curtailed Energy by Solar Penetration

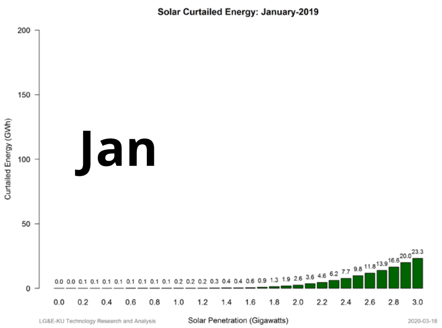


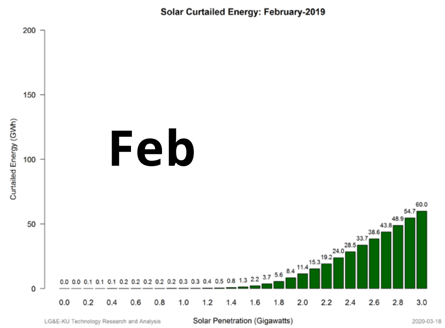
# Annual Curtailed Energy by Solar Penetration

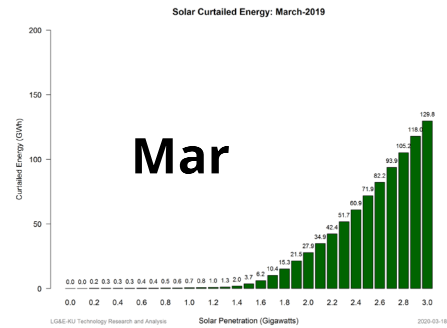
| Solar Penetration (MW) | Curtailed Energy (MWh) | Percentage of Potential (%) |
|---|---|---|
| 100 | 87 | 0.05 |
| 200 | 2,530 | 0.74 |
| 300 | 2,939 | 0.58 |
| 400 | 3,400 | 0.50 |
| 500 | 3,777 | 0.41 |
| 600 | 4,345 | 0.39 |
| 700 | 4,481 | 0.35 |
| 800 | 5,139 | 0.36 |
| 900 | 5,710 | 0.34 |
| 1000 | 6,752 | 0.36 |
| 1100 | 7,669 | 0.36 |
| 1200 | 9,717 | 0.42 |
| 1300 | 13,026 | 0.51 |
| 1400 | 18,095 | 0.66 |
| 1500 | 26,455 | 0.89 |

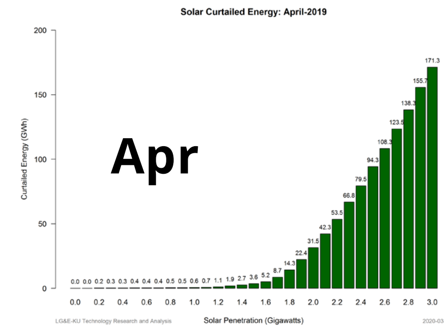
| Solar Penetration (MW) | Curtailed Energy (MWh) | Percentage of Potential (%) |
|---|---|---|
| 1600 | 39,934 | 1.26 |
| 1700 | 62,110 | 1.82 |
| 1800 | 92,319 | 2.55 |
| 1900 | 135,986 | 3.52 |
| 2000 | 185,401 | 4.56 |
| 2100 | 248,183 | 5.78 |
| 2200 | 315,415 | 7.02 |
| 2300 | 399,797 | 8.44 |
| 2400 | 484,317 | 9.80 |
| 2500 | 586,074 | 11.32 |
| 2600 | 688,023 | 12.78 |
| 2700 | 805,687 | 14.35 |
| 2800 | 924,405 | 15.87 |
| 2900 | 1,062,433 | 17.53 |
| 3000 | 1,195,771 | 19.08 |

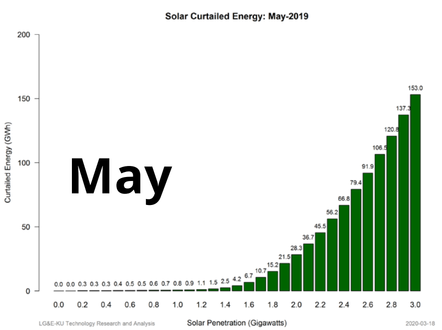
# Monthly Curtailed Energy by Solar Penetration

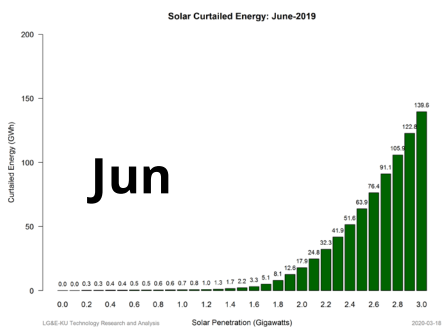


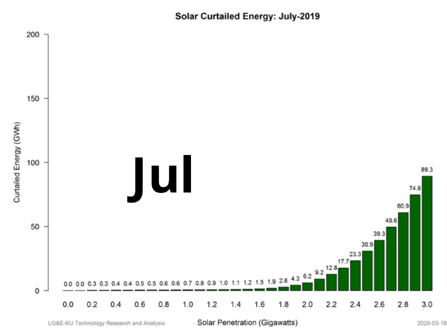



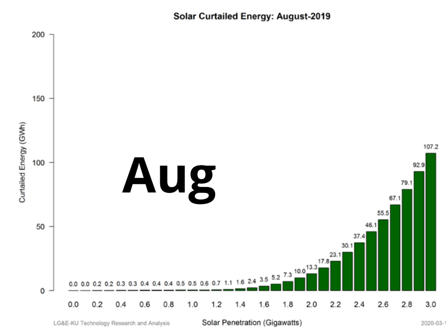



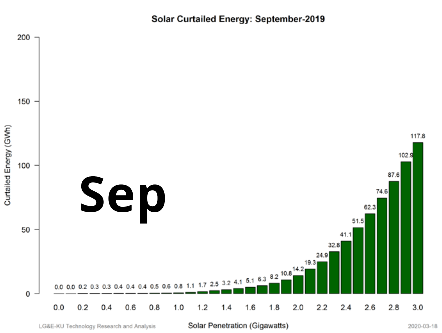



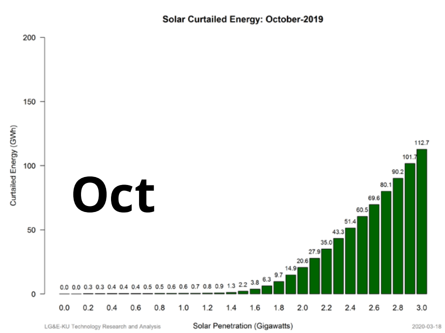



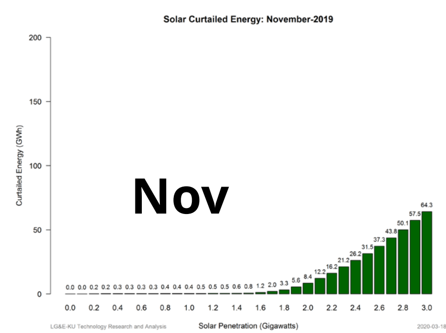



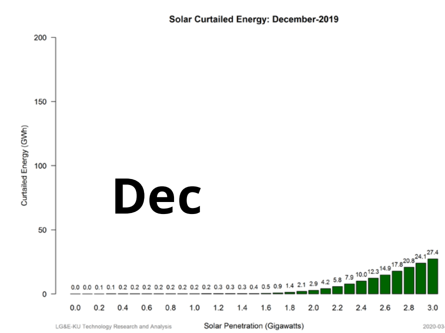



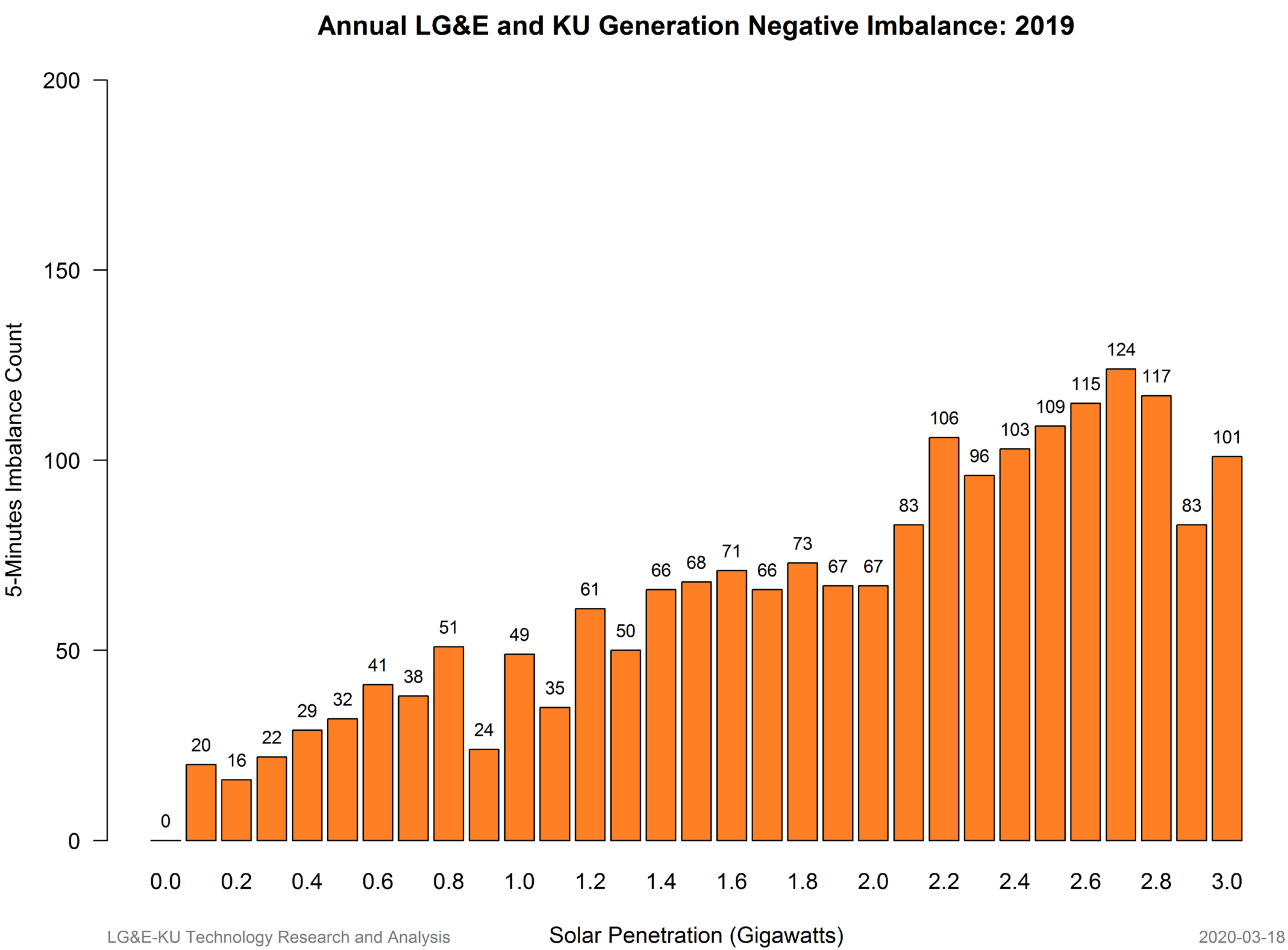



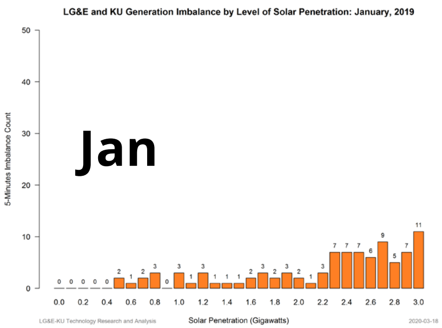


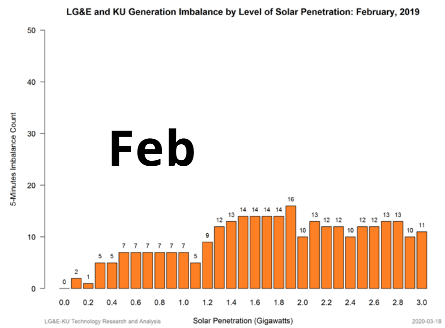

PPL companies

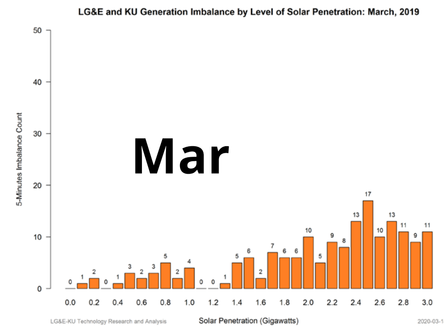
# Annual 5-Minute Negative Imbalances

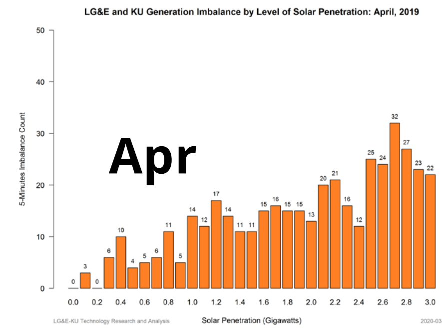


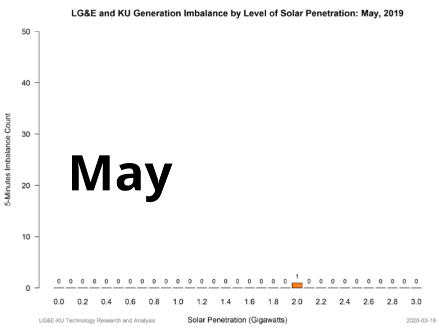
# Monthly 5-Minute Negative Imbalances

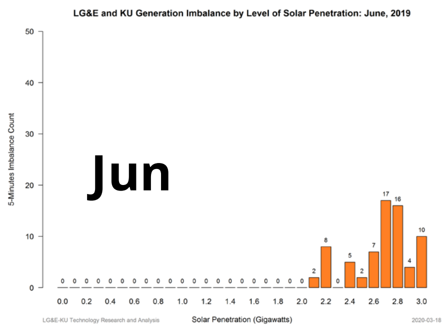


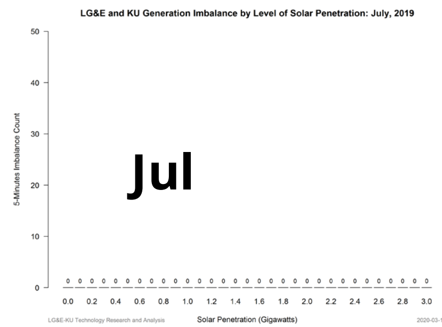



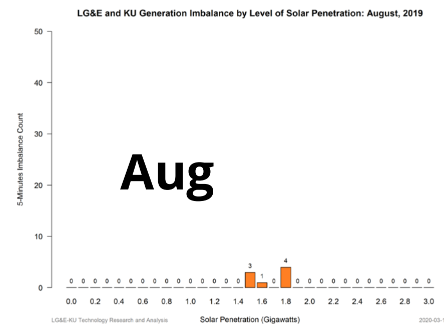



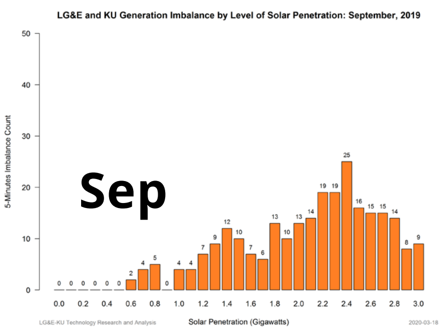



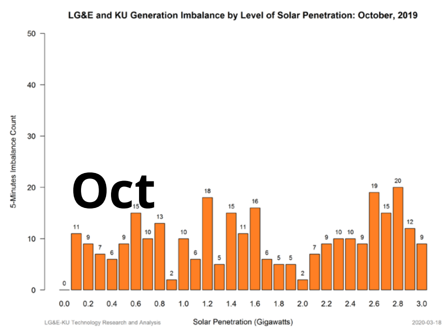



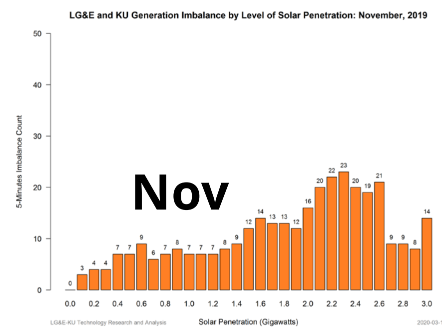



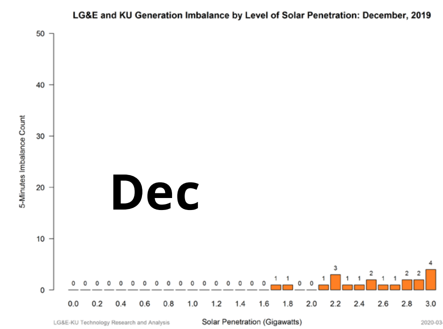





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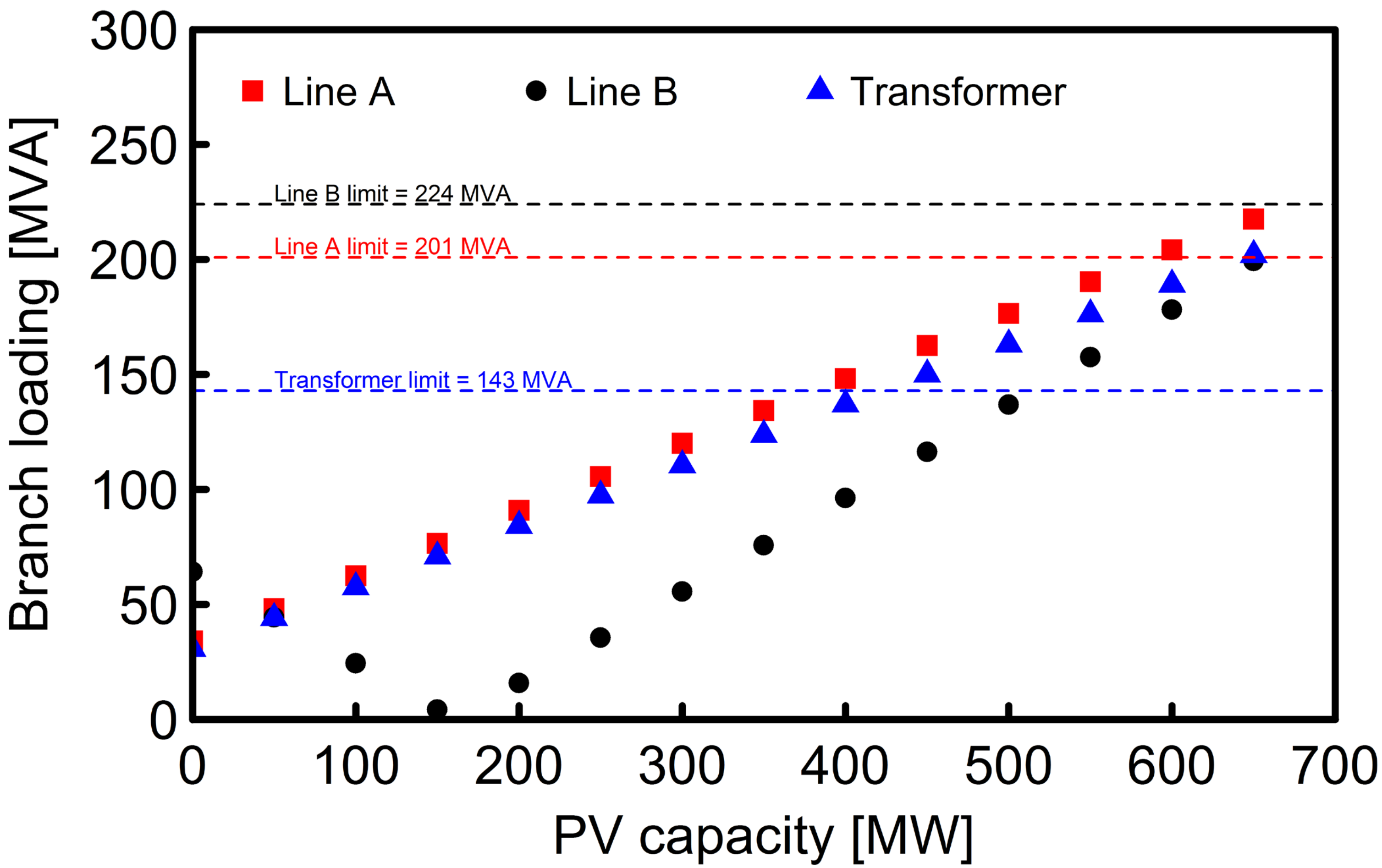
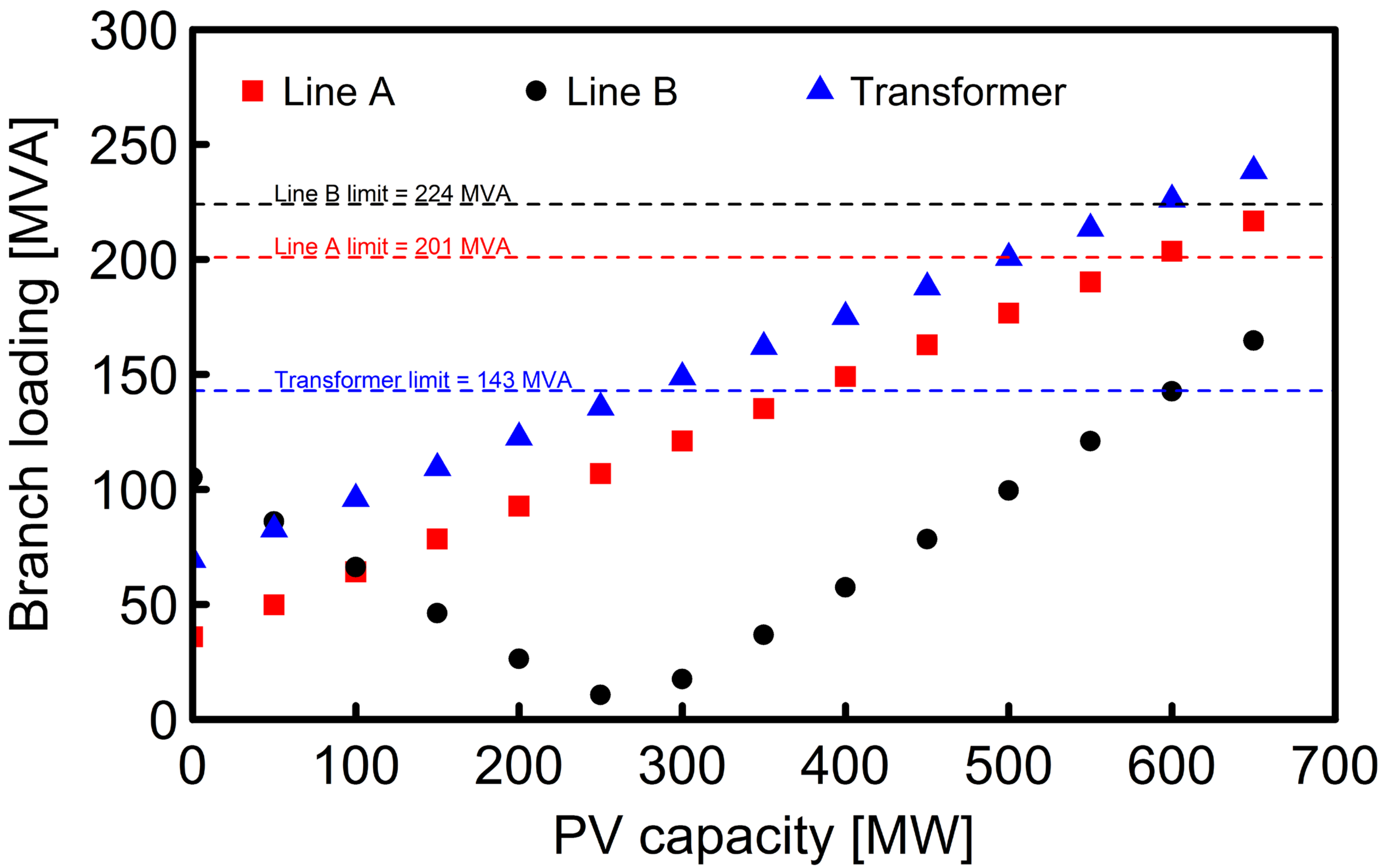
# Transmission Impacts

# Example Thermal Loading – Off Peak



# Example Thermal Loading - Peak



# Methodology

# Peer-Reviewed Methodology

Akeyo, Oluwaseun M., Aron Patrick, and Dan M. Ionel 2021. **"Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System"** *Energies* 14, no. 1: 169. https://doi.org/10.3390/en14010169

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# Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System

**Oluwaseun M. Akeyo [1], Aron Patrick [2] and Dan M. Ionel [1,*]**

[1] SPARK Laboratory, ECE Department, University of Kentucky, Lexington, KY 40506, USA; m.akeyo@uky.edu
[2] Louisville Gas and Electric and Kentucky Utilities, Louisville, KY 40202, USA; aron.patrick@lge-ku.com
* Correspondence: dan.ionel@ieee.org

**Abstract:** Significant changes in conventional generator operation and transmission system planning will be required to accommodate increasing solar photovoltaic (PV) penetration. There is a limit to the maximum amount of solar that can be connected in a service area without the need for significant upgrades to the existing generation and transmission infrastructure. This study proposes a framework for analyzing the impact of increasing solar penetration on generation and transmission networks while considering the responses of conventional generators to changes in solar PV output power. Contrary to traditional approaches in which it is assumed that generation can always match demand, this framework employs a detailed minute-to-minute (M-M) dispatch model capable of capturing the impact of renewable intermittency and estimating the over- and under-generation dispatch scenarios due to solar volatility and surplus generation. The impact of high solar PV penetration was evaluated on a modified benchmark model, which includes generators with defined characteristics including unit ramp rates, heat rates, operation cost curves, and minimum and maximum generation limits. The PV hosting capacity, defined as the maximum solar PV penetration the system can support without substantial generation imbalances, transmission bus voltage, or thermal violation was estimated for the example transmission circuit considered. The results of the study indicate that increasing solar penetration may lead to a substantial increase in generation imbalances and the maximum solar PV system that can be connected to a transmission circuit varies based on the point of interconnection, load, and the connected generator specifications and responses.

**Keywords:** hosting capacity; photovoltaic; PSS/E; economic dispatch; voltage violations; thermal limits; PV penetration; solar



**Citation:** Akeyo, O.M.; Patrick, A.; Ionel, D.M. Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System. *Energies* **2021**, *14*, 169. https://doi.org/10.3390/en14010169

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## 1. Introduction

Renewable energy resources are rapidly becoming an integral part of electricity generation portfolios around the world due to declining costs, government subsidies, and corporate sustainability goals. Large renewable installations on a transmission network may have potential impacts on the delivered power quality and reliability, including voltage and frequency variations, increased system losses, and higher wear of protection equipment [1]. Estimating the maximum hosting capacity of a transmission network may be used to determine the highest renewable penetration the system can handle without significant violations to the quality of the power delivered and the reliability of the grid.

Most recent literature has been focused on analyzing the impact of intermittent renewables on either generation or transmission systems only [2–5]. In [6], a methodology for estimating the solar PV hosting capacity based on steady-state circuit violations, without a detailed economic dispatch model was proposed. Typical dispatch models in the literature assume generation can always match load or set optimization constraints that are only acceptable for hourly dispatch models with relatively low load variations [7–9]. These hourly dispatch models may not be suitable for capturing the impact of PV systems for practical generation service areas, which record generation imbalance violations over duration as low as 15-min.

Furthermore, a substantial portion of literature has been focused on estimating the maximum PV hosting capacity for distributions systems and proposing network configurations that do not consider the contributions of conventional generators [10–13]. However, more than 60% of PV installations in the US are utility-scale setups typically connected to the transmission network [14]. Steady-state and transient analysis of transmission networks were presented in [6,15], but none of the works considered the variability of the connected loads or present a detailed economic dispatch to capture the responses of the conventional generators.

This research presents a framework for analyzing the impact of increasing PV penetration on both generation and transmission systems. Contrary to conventional approaches dispatching units with substantial intermittent renewable resources with hourly based dispatch models [7,16], this approach employs an M-M dispatch model capable of capturing the impact of large solar PV penetration and identifying minute-based periods of generation imbalance due to PV volatility and surplus power. The presented technique is also capable of analyzing the impact of increasing PV system penetration have on transmission circuits while considering the responses of conventional generators to changes in solar PV power.

The impact of increasing solar PV penetration was analyzed on a modified IEEE 12 bus system [17] with generators, including coal, natural gas combustion turbine (NGCT), natural gas combined cycle (NGCC), and a hydropower plant with practical unit specifications. This study uses generator models developed on data provided by LG&E and KU on operational units to simulate the responses of conventional generators to increasing solar PV penetration (Figure 1). Publicly available one-minute irradiance data for the 10 MW PV farm located at the utility's facility was used to model typical variation in solar irradiance [18]. The PV hosting capacity of the example generation and transmission network systems analyzed was estimated based on voltage, thermal, and generator dispatch violations.

**Figure 1.** The aerial view of the E.W. Brown generating station, which includes Kentucky's largest solar farm, hydropower plant, natural gas units, and coal fired power plants.

## 2. Proposed Minute-to-Minute Economic Dispatch Model

The real-time changes in load from minute to minute are relatively minimal due to aggregation. However, the volatility of the net demand on conventional thermal generators rises significantly with the increase in intermittent renewable energy penetration. Although it is nearly impossible to always match generation with demand for a service area, utilities are penalized by regulators for generation imbalances lasting longer than acceptable minutes [19,20]. Hence, conventional hourly dispatch models are not suitable to identify the generation imbalances and effectively capture the effect of solar PV intermittency on evaluated service area.

This approach employs a minute-based dispatch since the solar PV power variability due to cloud cover is expected to reduce as the plant capacity and footprint increases. The proposed minute-to-minute dispatch model in this study was developed for the IEEE 12 bus test system illustrated in Figure 2. The system which consists of four generating units was modified based on the specifications presented in Table 1 and subjected to realistic load variations for an example day in the Fall season. The efficiency of thermal generating units in terms of their heat rate vary with percentage output for different types of units (Figure 3). In this approach, the heat rates for thermal units are described as follows:

$$Q_g^R(P_g) = \frac{Q_g^{in}(P_g)}{P_g} \approx a_g P_g^2 + b_g P_g + c_g, \tag{1}$$

where $Q_g^R(P_g)$ represents the heat rate for unit $g$ with output power $P_g$; $Q_g^{in}$ the heat requirement; and $a_g$, $b_g$, $c_g$ are the heat rate co-efficient of the generator. Therefore, the operating cost for each unit may be expressed as:

$$C_g(P_g) = Q_g^R(P_g) \cdot F_g + Z_g, \tag{2}$$

where $C_g$ is the running cost for generator $g$; $F_g$, the fuel cost and $Z_g$, the fixed cost constant, which includes maintenance and emission reduction costs. Therefore, the proposed M-M dispatch model can estimate the running cost of the thermal units for specified output level within its limits of operation (Figure 4).

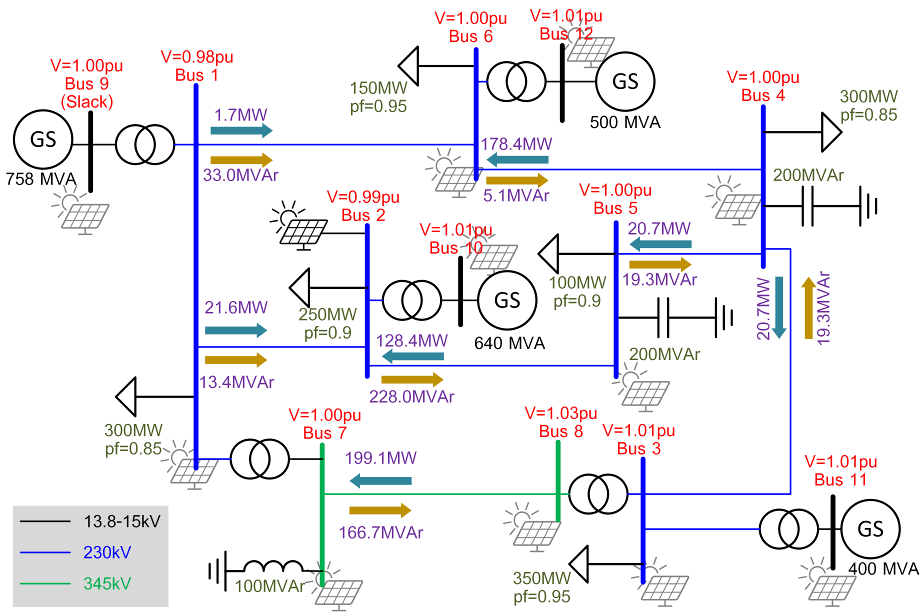


**Figure 2.** Single line diagram for the modified benchmark network with PV plant connected to bus 2 and values corresponding to approximately 65% (1450 MW) load level. The transmission circuit was completely assessed for PV connection at any of its buses.

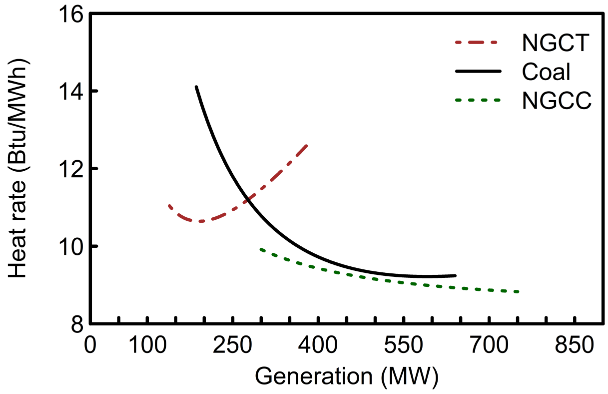


**Figure 3.** Example heat rate curve for natural gas combustion turbine (NGCT), coal, and natural gas combined cycle (NGCC) thermal generators considered in this study.

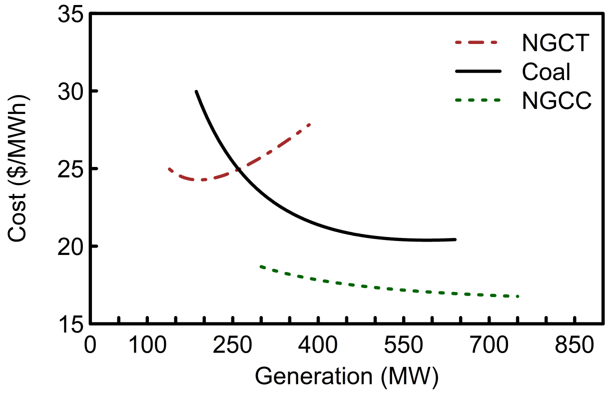


**Figure 4.** The operation cost in $/MWh including the fuel and auxiliary costs for the thermal units considered. The cost rate in $/h can be calculated as a product of the operation cost and the generation.

**Table 1.** Specifications for the generating units in the modified IEEE 12 bus test case studied.

| Bus No. | Type | Rating (MW) | Min Gen (MW) | Ramp (MW/min) | Heat Rate Co-Eff. a ($10^{-3}$) | b | c | Fuel ($/MMBtu) | Aux ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|
| 9 | NGCC | 750 | 368 | 10 | 0.4 | 7.7 | 630 | 1.76 | 1.23 |
| 10 | Coal | 640 | 288 | 7 | 5.5 | 2.7 | 1935 | 1.96 | 1.79 |
| 11 | NGCT | 384 | 203 | 9 | 20.7 | 2.7 | 753 | 1.76 | 5.54 |
| 12 | Hydro | 474 | - | - | - | - | - | - | - |

For a practical economic dispatch problem, the objective is to minimize cost and generation imbalance such that the cheapest combination of generators are regulated to meet demand. Therefore, the economic dispatch model objective can be expressed as:

$$\min \begin{cases} C_T = \sum_{g=1}^{G} C_g(P_g) \\ \epsilon = |P_T - L_c| \end{cases}, \tag{3}$$

where

$$P_T = P_1 + P_2 + \ldots + P_G, \tag{4}$$

$C_T$, represents the total operating cost for all units considered; $P_T$, the combined generator output; $L_c$, the combined service area load; and $G$ the total number of operational units including the PV plant. Following theoretical developments in [21], the minimum $C_T$ for each instance without considering generator constraints and transmission losses occurs when the total differential cost is zero and may be described as follows:

$$\partial C_T = \frac{\partial C_T}{\partial P_1} dP_1 + \frac{\partial C_T}{\partial P_2} dP_2 + \ldots + \frac{\partial C_T}{\partial P_G} dP_G = 0. \tag{5}$$

However, due to generator constraints including ramp-rate limitation of units the result from (5) may fall outside operation range.

Contrary to conventional approaches, this approach recognizes the practical limitations of generator units. The constraints for the considered thermal units are as follows:

$$P_g^{min}(t) \leq P_g(t) \leq P_g^{max}(t) \tag{6}$$

$$P_g^{min}(t) = \max\left[\underline{P_g}, \quad P_g(t - \Delta t) - \Delta t \cdot R_g^{down}\right] \tag{7}$$

$$P_g^{max}(t) = \min\left[\overline{P_g}, \quad P_g(t - \Delta t) + \Delta t \cdot R_g^{up}\right] \tag{8}$$

where $P_g^{max}(t)$ and $P_g^{min}(t)$ are the maximum and minimum output power for unit $g$, respectively; $\overline{P_g}$ and $\underline{P_g}$ are the specified maximum and minimum generator operation limits; $R_g^{up}$ and $R_g^{down}$, the generator rising and falling ramp rates, respectively.

This study is focused on the impact of increasing PV penetration on an example system with five generators. The proposed framework economic dispatch model employs a multi-objective genetic algorithm (GA) to minimize $C_T$ and $\epsilon$ for the three thermal units in the system and the "non-dispatchable" units (PV and hydro) output are set based on reference values from practical modules. The solar plant reference power module was developed based on measured irradiance data retrieved from an operational solar PV farm. The PV output power is expressed as follows:

$$P_{pv} = \frac{\gamma}{1000} \times \eta \times \overline{P_{pv}}, \tag{9}$$

where $P_{pv}$ is the PV plant power, $\gamma$ is solar irradiance in W/m$^2$; $\eta$ is the inverter efficiency, and $\overline{P_{pv}}$ is the rated capacity. The algorithm goes through multiple combinations of generator set points limited by $P_g^{min}(t)$ and $P_g^{max}(t)$ for each unit to establish a Pareto front. Since the primary objective of the utilities is to meet demand, the design with the least amount of imbalance is selected for the simulation time-step (Figure 5).

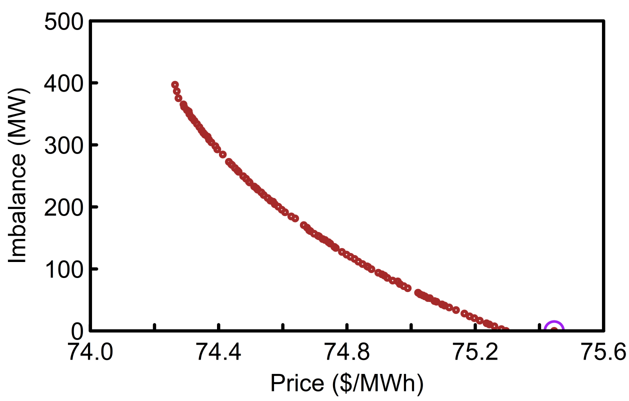


**Figure 5.** The multi-objective optimization Pareto front for example minute. The selected design is the one with the minimum imbalance for every case.

To identify periods of over- and under-generation, the proposed M-M dispatch model assumes the generators in the transmission circuit are solely responsible for meeting demand for the concerned service area without need for off system sales and electricity power trading. Factors such as unit commitment and outage are beyond the scope of this study. Therefore, all units are assumed to be available and committed throughout the example day.

## 3. Conventional Generators Response to Increasing PV Penetration

Increasing solar penetration can make it more challenging for grid operators to balance generation with load in real time, since generating units are committed based on load forecast and level of uncertainty. In this study, the integrated PV farms are operated in "must-take" modes, in which thermal units are turned down to accommodate solar PV penetration. The relatively high power variation of the PV plant for the example day considered leads to significant generation imbalance during periods when the operating units cannot ramp up or down fast enough for meet demand.

Due to the minimum generation limit of the available thermal unit, a significant level of over-generation may be observed at hours between 9:00 and 13:00, when the generators could not ramp down further to accommodate the increasing PV penetration (Figure 6). In addition to the rest time required to restart thermal units, a significant amount of time, up to 24 h for some coal units is required to restart start them which makes it extremely challenging to turn off the units at midday and restart them for evening peak [22].

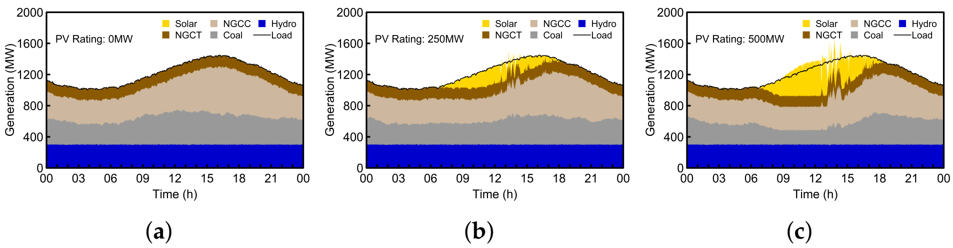


**Figure 6.** Minute-to-minute (M-M) unit economic dispatch highlighting the impact of increasing PV penetration on an example generation portfolio. The results indicate that large PV penetrations may lead to both over- and under-generation scenarios where combined power from units cannot match demand. The presented analysis include (**a**) no PV, (**b**) 250 MW PV, and (**c**) 500 MW PV penetration case studies.

The current solar PV regulatory standards may not be sufficient for managing high intermittent renewable sources penetration and new standards will be required to ensure grid stability in a future grid [23,24]. Furthermore, the penetration of distributed renewable sources such as rooftop solar will lead to substantial changes in the apparent load on the transmission network that may call for additional regulations. In this study, a generation violation or imbalance count is recorded when the area control error, ACE, exceeds ±20 MW for defined consecutive minutes. The ACE is expressed as:

$$ACE = (T_m - T_s) + \beta_f (f - f_s), \tag{10}$$

where $T_m$ and $T_s$ are the measured and scheduled tie line lows, $f$ and $f_s$, the measured and scheduled frequency, and $\beta_f$ the frequency bias constant for the area. Frequency variation due to generation imbalance is beyond the scope of this study, therefore it was assumed that $f$ = $f_s$, and $T_s$ is always equal to zero. Hence, for this analysis (10) can be re-written as:

$$ACE = T_m = P_T - L_c. \tag{11}$$

The over- and under-generation imbalance count for the example day was evaluated for increasing PV penetration. A significant level of over-generation can be observed at solar PV penetration levels exceeding 400 MW (Figure 7). This is mainly due to the inability of the available units to operate at values below their minimum generation limits during periods of surplus solar generation. For the example day analyzed, there was no under-generation violation lasting more than 15 consecutive minutes (Figure 8). However, significant under-generation violation counts for 5 and 10 consecutive minutes, which was relatively constant for PV penetration above 350 MW was recorded. These violations are primarily due to the intermittent behavior of the PV systems and generating units not being able to ramp fast enough to supply deficit power due to sudden shading of the solar panels.

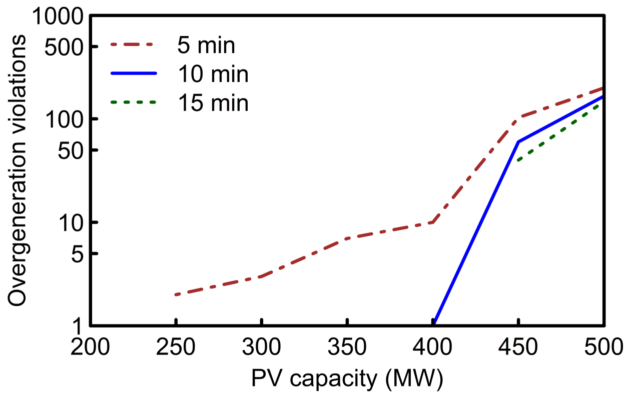


**Figure 7.** Example day over-generation violation count. In this approach a violation count is recorded when the dispatch imbalance exceeds 20 MW over defined consecutive minutes (5, 10 and 15).

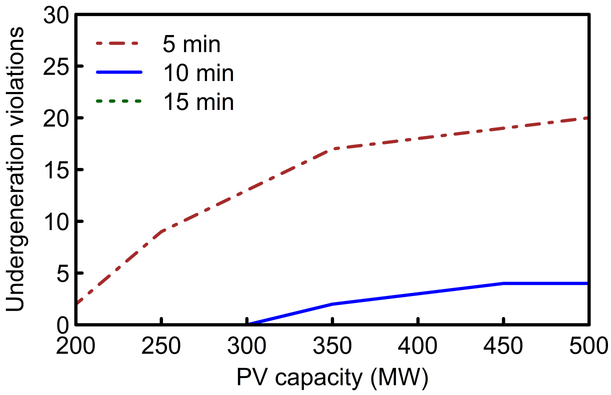


**Figure 8.** Under-generation violation count at increasing PV penetration rate. Under-generation occurs when PV becomes suddenly shaded and thermal units cannot ramp up fast enough to supply deficit power.

Solar power curtailment can be an effective tool for managing over-generation, in which the solar PV plant output may be held back when there is insufficient demand to consume production. This study examined how much curtailment will be required to address solar over-generation for the presented generator portfolio over the example day (Figure 9). An exponential increase in the curtailed PV energy to avoid over-generation violations was recorded, with rapid increase in curtailment for PV capacity above 400 MW. Due to the substantial PV energy curtailed, over 2% reduction in PV capacity factor was reported at 500 MW penetration level (Figure 10).

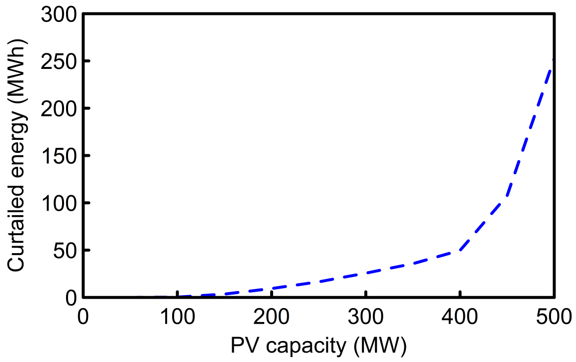


**Figure 9.** Curtailed energy solar energy for example day. In order to limit over-generation, an exponential increase in the total solar PV power curtailed can be observed.

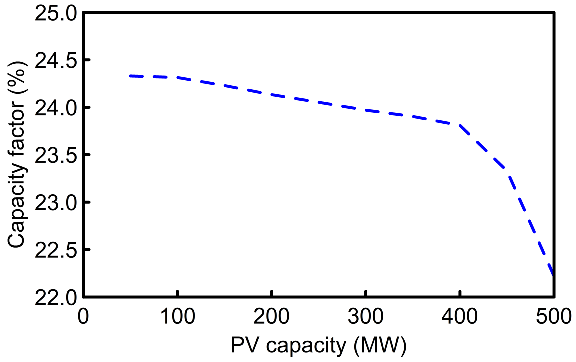


**Figure 10.** PV plant capacity factor based on penetration. Capacity factor can be observed to reduce with increase in curtailed power.

Increase in solar PV penetration is expected to lead to significant reduction in running cost without considering the capital cost for the PV system. It is, however, important to recognize that PV penetration may lead to more aggressive usage of fast ramping units such as NGCTs, which are typically the most expensive units in generation portfolios. This study evaluated the cost savings for the example day due to increase in PV penetration. A somewhat steady increase in cost savings was reported for solar PV penetration above 80 MW (Figure 11). However, due to generator commitment and increased operation of the NGCT unit for managing the solar PV variation over the example day, no cost savings was recorded for solar PV penetration below 80 MW.

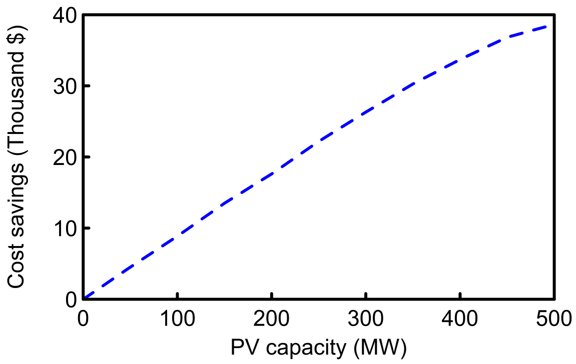


**Figure 11.** Operation cost saving due to increase in PV penetration. For the example day considered, an increase in operation cost was observed for PV penetrations below 500 MW due to operation of inefficient units to meet demand.

## 4. Modified Benchmark Transmission Network

The modified benchmark transmission system analyzed in this work represents a small islanded power system network with 12 buses and four generating units (Figure 2). This modified transmission network is based on the generic 12-bus test system developed for wind power integration studies presented in [17]. The transmission network base case was developed in PSSE with a single transmission line connecting buses 3 and 4, as opposed to the parallel cables in the initial setup.

At steady-state without renewable integration, the transmission network total system load is approximately 65% of the total generation capacity. The bus voltage voltages vary between 0.98 pu to 1.03 pu. In this example, each of the transmission lines is rated for a maximum of 250 MVA power flow except for the transmission lines connecting buses 7 to 8 and 3 to 4, which are rated to 500 MVA. At 65% load level without renewable integration, the maximum loading for any of the transmission lines is 71%, which is the power flow between buses 6 and 4.

Solar PV penetration have the maximum impact on generation during periods when load is relatively low. For transmission networks, maximum PV impact is observed during peak periods, when load is rather high and transmission lines are near saturation. In this approach, the transmission network was evaluated for the analyzed example day peak demand and the generating units were dispatched accordingly with respect to minimum operating cost and solar PV penetration.

The benchmark model was further modified to enable renewable system integration, such that a solar PV farm may be connected to either of its 12 buses. In order to connect the PV plant to a selected bus, an additional transformer is introduced to connect the PV plant terminal to the corresponding bus. Based on typical regulatory requirements, the PV plant is configured to be capable of operating at 0.95 power factor to support scheduled grid voltage at the point of interconnection (POI) [25].

## 5. Proposed Framework for Network PV Hosting Capacity

The PV hosting capacity for a transmission network is defined as the maximum solar PV capacity that may be connected to the system without significant upgrades to its circuit to ensure steady operation. The maximum hosting capacity of a transmission circuit depends on multiple factors including the bus voltage variation, thermal limits of the transmission lines, frequency variation, fault currents as well as regulated factors such as total harmonic distortion and grid codes. This study focuses on the maximum PV capacity that may be connected to any one of the buses in the example transmission network without violating the bus voltages or the thermal limits of the circuit branches.

The proposed framework established as a combination of modules developed in Python and transmission case studies in PSSE, may be employed to estimate the hosting capacity for a defined transmission network. Opposed to conventional approaches, this framework employs a practical and detailed economic dispatch model, which defines the output power of all available generating units based on combined running cost. This dispatch model also respects generator minimum power limit and ensures units are set to values within their operation limits. Hence, the combination of units that meet load at the least cost are dispatched for each case study analyzed.

The framework allows the user to define the potential buses for PV connections, the range and maximum PV capacity to be analyzed, and the load levels to be considered. The simulation study is initialized with for the based case without solar PV penetration and the case study is evaluated. The combined load for the analyzed instance is then distributed to all the load buses at a ratio and power factor identical to the base case. The transmission network is then modified such that the minimum PV capacity to be evaluated is connected to the first candidate bus to be analyzed. All the available generators are re-dispatched to accommodate the increase in PV penetration.

The modified circuit is solved in PSSE, and the connected PV rating is increased if the solution converges. The framework keeps increasing the connected PV rating at predefined steps until solution failure or maximum PV rating to be analyzed, after which it resets to a minimum PV rating for the next bus or load level. The simulation comes to an end after the combinations of all PV ratings, connection buses and load levels have been exhaustively tested and results extracted (Figure 12). Based on the criteria defined for the system circuit, the collected results are therefore analyzed to determine the system's maximum hosting capacity.

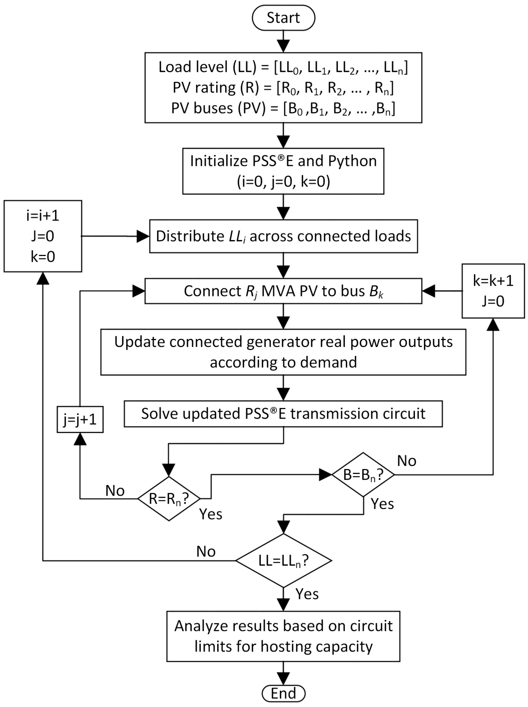


**Figure 12.** Operational flow chart for the proposed framework for estimating the hosting capacity on a transmission network. The steady-state impact for increasing solar PV capacity at different POI was evaluated to estimate the maximum PV hosting capacity for the network.

## 6. Transmission Network Response to Increasing PV Capacity

The proposed framework was employed to estimate the PV hosting capacity for the modified IEEE 12 transmission network. The PV hosting capacity was evaluated based on the bus voltage responses of the network, thermal loading and circuit solution convergence. The network was evaluated at 1450 MW combined load level, which represents the peak demand for the example day analyzed. Up to 500 MW PV penetration level was analyzed for the defined POI and the operational conventional generators were re-dispatch for each case to ensure the combination generator output power with the least cost is selected.

Contrary to conventional assumptions, increasing PV penetration does not only lead to increase in bus voltage. This capability for increasing solar PV capacity to lead to both increase and decrease in bus voltages was demonstrated in this study. Variations in bus voltage in some cases are due to substantial changes in power flow, hence significant changes in the voltage drop across the transmission lines. Utilities are typically regulated to maintain their bus voltages within certain limits, and this study assumes a violation when any of the bus voltages exceeds 1.1 or below 0.9 pu. Due to multiple factors including substantial circuit violations, networks solutions for PV capacity beyond certain values do not converge and such cases are only evaluated based on available solutions. The maximum and minimum bus voltages for the network varies based on the PV POI as illustrated in Figure 13. Hence, up to 320 MW PV capacity can be connected to any of the transmission circuit buses without any voltage violation.

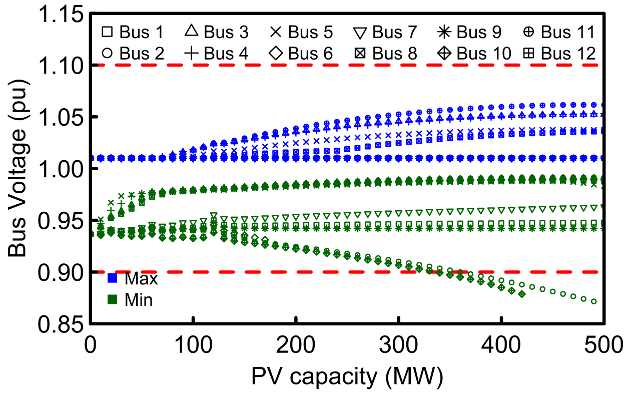


**Figure 13.** The maximum and minimum bus voltage variation for increasing PV capacity over multiple points of interconnection (POI). A PV capacity is undesirable if it leads to bus voltage variation above 1.1 or below 0.9 pu.

The maximum and minimum bus voltage in a transmission network is significantly influenced by the scheduled voltages of the connected generator units. Hence, a measure of the maximum and minimum bus voltages alone may not be able to capture the impact of increasing solar PV penetration. In addition to the maximum and minimum bus voltage limits, utilities are typically required to maintain bus voltage variation within certain values. This maximum voltage deviation can also be an indicator of the expected voltage variations due to the PV intermittency. For this study, a PV capacity that leads to bus voltage deviation that exceeds 0.08 pu is undesirable. The maximum voltage deviation varies based on PV capacity and POI as illustrated in Figure 14. Based on this analysis, up to 140 MW PV may be connected to any of the circuit buses with bus voltage deviations exceeding 0.08 pu.

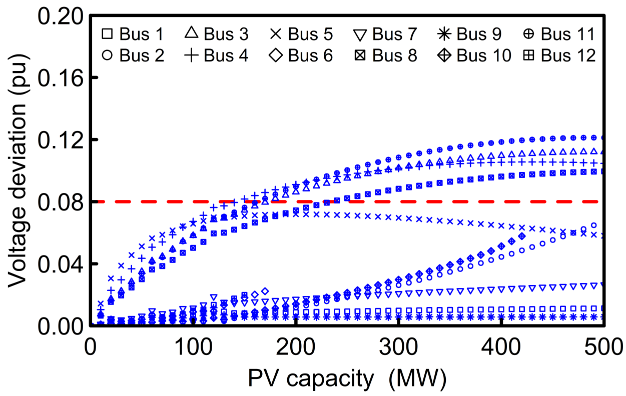


**Figure 14.** Maximum bus voltage deviation for defined PV capacity. A violation is recorded if the maximum voltage deviation exceeds 0.08 pu. The maximum voltage deviation is also an indicator of the expected voltage variation due PV intermittency.

Transmission line power flow are typically limited to restrict the temperature attained by energized conductors and the resulting sag and loss of tensile strength. This study focuses on the maximum PV penetration the network can sustain at steady state of a substantial period of time. Hence, the percentage loading for on all the transmission lines were evaluated for defined solar PV capacity. A thermal violation is recorded when the maximum transmission line loading exceeds 100% of its rated capacity. For the example network considered, buses 10, 11 and 12 are the least desirable for PV connection without overloading any of the transmission lines (Figure 15). Based on this analysis, up to 110 MW PV may be connected to any of the buses without any thermal violation.

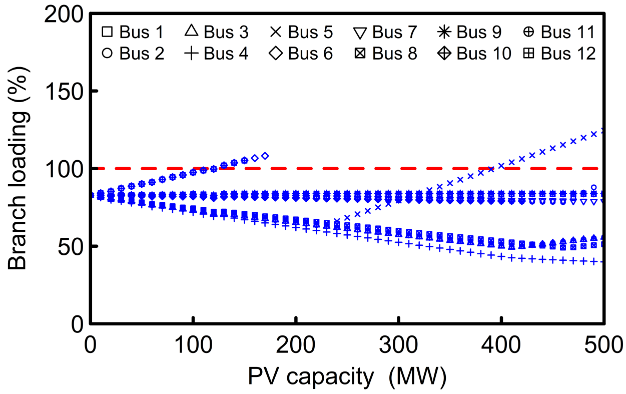


**Figure 15.** Maximum transmission line loading. Depending on the POI, PV integration may lead to substantial reduction in transmission line loading.

For this example study, a PV capacity is acceptable if all the bus voltages are within 0.9–1.1 pu, voltage differences with and without PV do not exceed 0.08 pu for any bus, and the thermal loading for any of the transmission lines is below 100%. Study is primarily focused on PV penetrations without significant changes to existing infrastructure, therefore, supplementary devices such as voltage regulators, capacitor banks, and other complementary tools were not considered. This study demonstrates that the maximum PV capacity without any network violation depends on the PV POI (Figure 16). Based on the maximum PV capacity for the analyzed cases without voltage or thermal violations, the preferred PV POI for the analyzed network are buses 1, 7 and 9.

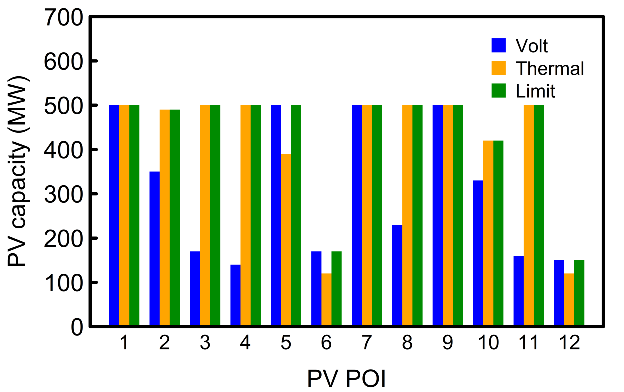


**Figure 16.** Maximum PV hosting capacity with respect to the circuit solution limit, voltage violation and thermal limits at peak load level.

## 7. Conclusions

This paper proposes an analytical framework, which includes a minute-to-minute economic dispatch model and a transmission network analyzing module for the evaluation of large solar PV impacts on both the generation and transmission systems. This framework can be employed for multiple applications including studies for estimating the maximum solar PV capacity a service area can support, the generation violations due to solar PV penetrations, the preferred location to connect solar PV plants, and the power system violations on the transmission network due to solar PV penetration. Furthermore, the proposed framework may be adopted for other intermittent sources such as wind power plants, and evaluate their effect on both the generation and transmission network system.

The detailed technical benefits for the proposed framework were demonstrated through the evaluation of the impact of increasing solar PV penetration on both the generation and transmission network for a modified IEEE 12 bus system with four conventional generators. Contrary to conventional approaches based on hourly dispatch models, the proposed technique employs a detailed minute-to-minute economic dispatch model to capture the impact of increasing PV penetration and identify periods of generation imbalance suitable for regulatory practices. Additionally, the framework was used to estimate the maximum PV hosting capacity for the transmission network with regards to the bus voltage and transmission line violations.

Based on the results for the example transmission circuit and generators responses for the day evaluated, the maximum capacity of the solar PV plant a service area can sustain without needing significant upgrades to the existing infrastructure depends on, the available unit specifications, the PV point of interconnections, and the voltage and thermal limits of the transmission network buses and lines, respectively. The results from the example 2248 MW system evaluated indicate that the system can sustain up to 400 MW, 17.8% of capacity, PV penetration without substantial generation violation and up to 120 MW PV plant can be connected to any of the buses in the transmission network without any voltage or thermal violation at peak load. The hosting capacity of the transmission network considering solar PV plants at multiple POI and the integration of battery energy storage systems to improve the acceptable PV capacity on the circuit are subjects of ongoing studies.

**Author Contributions:** Conceptualization, O.M.A., A.P. and D.M.I.; Formal analysis, O.M.A.; Funding acquisition, A.P.; Investigation, O.M.A.; Methodology, O.M.A., A.P. and D.M.I.; Supervision, Dan M. Ionel; Writing—original draft, O.M.A.; Writing—review & editing, A.P. and D.M.I. All authors have read and agreed to the published version of the manuscript.

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**Informed Consent Statement:** Not applicable.

**Data Availability Statement:** No new data were created or analyzed in this study. Data sharing is not applicable to this article.

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**Conflicts of Interest:** The authors declare no conflict of interest.

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**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.61**

**Responding Witness: David S. Sinclair**

Q-2.61. What is the status of the Companies' carbon capture research and the status of carbon capture technologies? What is the Companies' assessment of the state of carbon capture and sequestration technologies, and how these technologies will evolve over the next 15 years? What are the Companies projections for how the cost of carbon capture and sequestration will change over the next 15 years. Please provide all data, reports and analysis to support the Companies' response.

A-2.61. The Companies have been partnering with the University of Kentucky (UK) since 2006 to investigate various technologies to reduce the cost of post-combustion $CO_2$ capture from stationary point sources, develop next-generation combustion technologies including chemical looping and direct air capture. One particular technology, amine-based post-combustion $CO_2$ capture, has been scaled up to the 0.7 MWe scale, installed and tested at the E.W. Brown Station for more than 8,000 hours since 2014. The only facility of its kind in Kentucky, this unit has proven invaluable for process intensification technology development, and knowledge gained on operations, chemical and waste management, capital and operating costs, and the energy required for solvent regeneration. Through this project, the Companies have demonstrated that carbon capture technology works, though it remains expensive and is thus rarely used.

The Companies have partnered with UK to develop technologies to capture atmospheric $CO_2$ and an advanced negative $CO_2$ emissions technology applicable to a NGCC plant, which produces hydrogen as a byproduct. Additionally, the Companies are partnering with EPRI, UK, Bechtel, and Vogt to prepare a proposal to US Department of Energy (DOE) to conduct a front-end engineering design (FEED) study for commercial-scale $CO_2$ capture at Cane Run station. The Companies are building on the success at the 0.7 MWe scale to explore options for carbon capture at Cane Run.

The Companies' cost and operating inputs for generation resources are based on NREL's 2021 ATB.[24] Figure 1 on page 5 of the *2021 IRP Resource Screening Analysis* shows generation technology cost forecasts for each technology option, including NGCC with CCS, over the next 15 years.

Carbon capture research with our partners at the University of Kentucky has resulted in at least 118 publications and 17 U.S. patents with another four pending. Some of the 118 publications, which support the Companies' views on CCS, are listed below.

1. Guojie Qi, Kun Liu, Alan House, Sonja Salmon, Balraj Ambedkar, Reynolds A.Frimpong, Joseph E.Remias and Kunlei Liu, (2018), *Laboratory to Bench-Scale Evaluation of an Integrated $CO_2$ Capture System Using a Thermostable Carbonic Anhydrase Promoted $K_2CO_3$ Solvent with Low Temperature Vacuum Stripping*, Applied Energy, January 2018, https://doi.org/10.1016/j.apenergy.2017.10.083
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[24] https://atb.nrel.gov/

Corrosion Science, Volume 106, 2016, Pages 281-292, ISSN 0010-938X, https://doi.org/10.1016/j.corsci.2016.02.013.

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8. Reynolds A. Frimpong, Bradley D. Irvin, Heather Nikolic, Kunlei Liu and Jose Figueroa, (2019), *Integrated hybrid process for solvent-based $CO_2$ capture using a pre-concentrating membrane: A pilot scale study*, International Journal of Greenhouse Gas Control, Volume 82, March 2019, Pages 204-209, https://doi.org/10.1016/j.ijggc.2019.01.016.
9. Reynolds A. Frimpong, Heather Nikolic, David Bahr, Gopi Kiran, Kunlei Liu, *Pilot scale testing of an advanced solvent in a 0.7 MWe post-combustion $CO_2$ capture unit*, International Journal of Greenhouse Gas Control, Volume 106, 2021, 103290, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2021.103290.
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**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.62**

**Responding Witness: Robert M. Conroy / David S. Sinclair**

Q-2.62. Regarding the impact of Electric Vehicle charging on peak loads, what measures are the Companies considering to incentivize customers to shift EV charging into lower load hours of the night?

A-2.62. See the response to PSC 1-18.

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**Question No. 2.63**

**Responding Witness: Stuart A. Wilson**

Q-2.63 Since the companies are already experiencing customers switching from gas appliances to electric, please provide more details of your expectations in that regard, and the implications for increasing both regular demand and peak demand for electricity?

A-2.63. The Companies' expectation is consistent with those modeled in the 2021 IRP base case load forecast and included in the confidential attachments to JI 1-3. The end-use model input assumptions come from Itron's East South Central region's outlook, which is derived from the Energy Information Administration's Annual Energy Outlook.

As discussed in the IRP and shown in the high load forecast scenario, a much higher saturation of electric space heating in the service territory would significantly increase winter energy requirements and peak demands. However, this is not the Companies' expectation for future electric space heating saturations in their service territory.

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**Case No. 2021-00393**

**Question No. 2.64**

**Responding Witness: Stuart A. Wilson**

Q-2.64. Can the companies model how expanded distributed generation (for example that might occur with the elimination of the 1% cap on net metered solar), and expanded utility scale solar combined with battery storage, could be used to moderate the effects of expanded EV adoption on load profiles

A-2.64. See the responses to JI 1.12, SREA 1-7, and AG 2-1(b). Because the Companies assumed a managed charging profile for EVs in the base forecast, expanded adoption of EVs does not materially impact peaks in summer or winter, as shown in Figures 5-21 and 5-22 of IRP Vol. I. Given this, there is no need to model this scenario.

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**Response to Joint Intervenors'**
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**Case No. 2021-00393**

**Question No. 2.65**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.65. With respect to the potential buildout of crypto-currency mining in Kentucky:

a. Explain whether or how the companies have incorporated crypto currency mining operations into their load forecasts.

b. Do the companies expect the development of crypto currency mining to impact the planned retirement of their coal-based power plants?

A-2.65.

a. See the response to JI 1.62. The base load forecast does not contemplate crypto-currency mining customer additions.

b. No. See the response to part (a).

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**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.66**

**Responding Witness: John Bevington**

Q-2.66. Provide the location for each solar EV charging station and non-solar EV charging station currently operated by the Companies.

a. Describe any efforts the Companies have made to explore cooperation with any Cities or schools on the electrification of bus fleets.

b. Has the Company evaluated incentives for electrification of bus fleets or other fleets for the benefits they would provide to the companies and customers?

A-2.66. The following are tables of company-owned and customer-hosted EV charging stations, their locations, and whether they are solar or non-solar powered stations.

**Company Owned EV Charging Stations**

| Location | Quantity | Solar or Non-solar |
|---|---|---|
| Energy Storage Testing Facility at E.W. Brown | 1 | Solar |
| LG&E Center Parking Garage, Louisville | 3 | Non-solar |
| Broadway Operations Center, Louisville | 1 | Non-solar |
| East Operations Center, Louisville | 3 | Non-solar |
| Auburndale Operations Center, Louisville | 2 | 1 - Solar<br>1- Non-solar |
| Lexington Operations Center, Lexington | 1 | Solar |
| Kentucky Utilities General Office, Lexington | 3 | Non-solar |

**Customer Hosted EV Charging Stations**

| Location | Quantity | Solar or Non-Solar |
|---|---|---|
| A.B. Sawyer Park, 9300 Whipps Mill Road, Louisville | 1 | Non-solar |
| Butchertown, 1100 East Washington Street, Louisville | 1 | Non-solar |
| Charlie Vettiner Park, Chenoweth Park Road, Louisville | 1 | Non-solar |
| Crescent Hill Public Library, 2736 Frankfort Ave, Louisville | 1 | Non-solar |
| Downtown Louisville, 220 West Main St, Louisville | 1 | Non-solar |
| Downtown Louisville, 315 East Main St, Louisville | 1 | Non-solar |
| Highlands, 1523 Hepburn Avenue, Louisville | 1 | Non-solar |
| Iroquois Park, Knoll Gate Rd, Louisville | 1 | Non-solar |
| Seneca Park, 3101 Rock Creek Rd, Louisville | 1 | Non-solar |
| Shawnee Park, 460 Northwestern Pkwy, Louisville | 1 | Non-solar |
| 116 North 5th St, Danville | 1 | Non-solar |
| 201 South Main St, Elizabethtown | 1 | Non-solar |
| Muhlenberg Sports Park - 200 County Park Drive, Greenville | 1 | Non-solar |
| 159 East High St, Lexington | 1 | Non-solar |
| One Quality Street, Lexington | 1 | Non-solar |
| McConnell Springs, 416 Rebmann Lane, Lexington | 1 | Non-solar |
| 721 Press Ave, Lexington | 1 | Non-solar |
| City Hall, 101 East Main St, Midway | 1 | Non-solar |
| Morehead State University, 121 East 2nd Street, Morehead | 1 | Non-solar |
| City Hall, 239 West Main St, Richmond | 1 | Non-solar |

a. The Companies previously engaged Black & Veatch Management Consulting, LLC to support an electric bus collaborative process per the Stipulation and recommendation in Case Nos. 2016-00370 and 2016-00371. Both Louisville Metro and Lexington Fayette Urban County Government were actively involved in the collaboration. The process per the Stipulation and recommendation was to focus on "economical deployment of electric bus infrastructure ... as well as possible cost-based rate structures …." As the collaborative progressed, the parties provided input to the study, but the formal study was not finalized by agreement of the collaborative parties.

b. The Company has not evaluated incentives for electrification of bus fleets or other fleets.

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**Question No. 2.67**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.67. How did the Companies include consideration of weather extremes into the IRP planning process? Do the Companies' forecasts and planning take account of the risk of more extreme weather in the future, as is expected due to climate change, and as we have already been experiencing in recent years?

A-2.67. See the response to JI 1.16. Extreme weather is considered in the Reserve Margin analysis. The likelihood of extreme weather in 2025 is assumed to be the same as the likelihood of extreme weather experienced over the past 48 years. In both the summer and winter, there are a wide range of temperatures modeled, as displayed in Figure 5-3 of IRP Vol. I.

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**Case No. 2021-00393**

**Question No. 2.68**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.68. The number of tornadoes doubled in the period 2000-2020 compared to 1980-2000. Clearly extreme weather and climate patterns are changing. Note that all the peak load events were in the last eleven years. But on page 21 pdf, Vol 1, the companies state that for the Reserve Margin Analysis, they based their forecasts on weather going back 48 years. How do the Companies justify giving the same weight to weather data from 1973-1988 as to what occurred in 2005-2020?

A-2.68. As devastating as tornadoes are, the Companies are unaware of any data showing that they significantly affect electric demand or energy consumption. Ambient air temperature, on the other hand, correlates closely with electric demand and energy consumption, particularly for residential customers. As shown in Figure 5-10 of IRP Vol. I (page 22 pdf), the weather years that resulted in the highest predicted 2025 peaks in summer and winter occurred in the 1980s. Indeed, some of the most extreme weather events seen in Louisville occurred prior to 2005; putting reduced weight on these events because they occurred more than 20 years ago does not seem prudent for long-term planning purposes. Indeed, the Companies would include data prior to 1973 if reliable daily or hourly weather data were available. A few examples of extreme temperatures that occurred in the Companies' service territories in or before 1994 are:

- Winter of 1977-1978 – Ohio River freezes[25]
- July 1936 – highest temperature ever recorded in Louisville (107° F)[26]
- January 1994 – lowest temperature ever recorded in Louisville (-22° F)[27]

[25] **https://wfpl.org/ohio-river-frozen/.**
[26] **https://www.weather.gov/lmk/top10heat.**
[27] **https://www.weather.gov/lmk/toptencoldevents; https://www.currentresults.com/Yearly-Weather/USA/KY/Louisville/extreme-annual-louisville-low-temperature.php.**

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.69**

**Responding Witness: John Bevington**

Q-2.69. How will the Advanced Metering Initiative help with Demand Side Management? Please give details. For example:

a. What data and DSM pilot programs (mentioned on page 17 volume 1) will be associated with the implementation of the AMI?

b. Detail possible ways implementation of AMI will lead to energy reductions and to demand impacts and give details of the estimated size of impacts.

A-2.69. Given that the analysis and determination of potential offerings has only just begun, it is too soon to know what data and programs will be offered.

a. See the response above.

b. See the response above.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.70**

**Responding Witness: John Bevington**

Q-2.70. On page 94, the companies state that their DSM programs have been a "tremendous success", and on page 102 state: "...the Companies project that the portfolio of programs will reduce demand by 179 MW through 2025 as well as achieve energy savings of approximately 215 GWh."

a. Can the companies indicate what metric should be used to evaluate the success of the DSM programs and size of these savings? For example a 215 GWh savings represents less than 1% of current or projected energy requirements (Table 8-17, pg 105 pdf). Is there an alternative metric that should be used to evaluate the programs? For example, how do the companies' savings compare to DSM programs in other states? (Note that the ACEEE 2020 State Energy Efficiency Scorecard (https://www.aceee.org/state-policy/scorecard) ranks Kentucky 33 out of 50 states, and Kentucky scores poorly in their category Utility and Public Benefits Programs and Policies).

b. Can the companies indicate their energy saving goals for the entirety of the planning period (i.e. beyond 2025)?

c. How does the cost of existing or planned demand side resources compare to the cost of supply side resources in meeting customer demand?

A-2.70.

a. The Companies believe a successful DSM-EE program is one that customers find desirable, contributes to safe and reliable service at the lowest reasonable cost, complies with KRS 278.285, and satisfies the Commission-approved and -applied cost-benefit tests.

b. The Companies have not historically set forward-looking demand or energy reduction goals for their DSM-EE programs. Instead, they seek to develop and deploy DSM-EE programs that meet the criteria discussed in the response to part a. above. When proposing such programs to the Commission for approval, the Companies project what they believe demand and energy reductions will be based on a variety of factors, including projected customer participation.

c. This planning and development process is currently underway on the DSM side, thus the cost-effectiveness results of demand-side resources are not yet available.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.71**

**Responding Witness: John Bevington**

Q-2.71. Please explain the companies' cost benefits analyses of DSM programs (including energy efficiency programs):

a. Please provide all data and analysis performed regarding all DSM programs considered for implementation during the planning period. Please include all Benefit-Cost analyses and all cost tests utilized for each program and identify each program that was evaluated.

b. Did cost benefit analyses include potential avoided transmission or distribution investments? If not, why not?

c. Did cost benefit analyses include avoided pollutants and environmental damage, avoided negative health impacts, and the avoided costs of these (such as those costs quantified in: https://www.epa.gov/statelocalenergy/public-health- benefits-kwh-energy-efficiency-and-renewable-energy-united- states; and https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialC ostofCarbonMethaneNitrousOxide.pdf)?

d. If the companies have not used the Societal Cost Benefit Test in considering DSM offerings, please explain why not.

A-2.71.

a. See the response to PSC 1-4.

b. No. See the response to PSC 1-4.

c. No. See the response to PSC 1-4. See also the responses to Question Nos. 2.13, 2.53, and 2.57.

d. See the responses to Question Nos. 2.13 and 2.53.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.72**

**Responding Witness: John Bevington / Stuart A. Wilson**

Q-2.72. On p.13 of Vol. III, the Companies state, "the Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunities for new DSM programs that will be evaluated with data and pilot programs associated with the implementation of AMI." Please explain why DSM programs, which the Companies describe as being "a tremendous success", were not thoroughly evaluated for their potential to meet the Companies' resource requirements and provide direct benefits to their customers.

A-2.72. See the response to PSC 1-4.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.73**

**Responding Witness: John Bevington / Stuart A. Wilson**

Q-2.73. On p.94 (Volume I of IRP), the Companies state that their DSM programs have been a "tremendous success."

a. Why then does the IRP indicate all DSM programs ending after 2025 and providing no further incremental energy savings?

b. Why have the Companies not evaluated the use of demand side management, energy efficiency, and distributed energy resources as system resources on par with traditional supply resources?

A-2.73.

a. The current DSM Portfolio is currently only approved through the end of 2025, which is why there are no projections for incremental energy and demand impacts beyond this date.

b. See the response to PSC 1-4.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.74**

**Responding Witness: Stuart A. Wilson**

Q-2.74. Have the Companies evaluated how to provide the greatest benefits to their customers through the strategic utilization of Distributed Energy Resources in all its forms (DERs, including but not limited to DSM, energy efficiency, distributed generation, battery storage, demand response)? Have the Companies evaluated how the benefits of DERs can be shared most broadly among their customers, especially low-income, and historically underserved and marginalized communities?

A-2.74. The Companies compared the costs of utility-scale and private solar and determined that utility-scale solar is lower cost (see Section 2.2.1 in the Resource Screening Analysis). The Companies' base load forecast assumes energy efficiency and DSM reduce energy requirements by 6% by 2036 (see IRP Vol. I, p. 5-26). The Companies did not evaluate distributed battery storage. See the response to PSC 1-4. See also the responses to Question Nos. 2.8 and 2.13.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.75**

**Responding Witness: John Bevington**

Q-2.75. Refer to Vol. I, Table 8-12 "KU and LG&E Demand Side Management Energy and Demand Impacts (Incremental)", particularly the second page, showing "DSM Summer Peak Demand Reduction (MW)."

a. Please clarify if the negative values for "Residential and Small Nonresidential Demand Conservation" are intended to reflect an increase in demand. If so, please explain in full how this demand conservation program increases the summer peak demand.

b. Please clarify whether the negative values for "Total Annual Demand Reduction" are intended to reflect a net increase in demand. If so, please explain in full how the cumulative effect of the Companies DSM programs results in a net increase in the summer peak demand.

A-2.75.

a. See the response to JI 1.14 (c)

b. See the response to JI 1.14 (c)

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.76**

**Responding Witness: Stuart A. Wilson**

Q-2.76. In Table 8.1, Vol. I, p.76 of pdf, please explain what "CSR" and "DCP" refer to.

A-2.76. CSR refers to the Companies' interruptible industrial customers under the Curtailable Service Rider tariff. DCP refers to the Companies' Residential and Non-Residential Demand Conservation Program through which customers' air conditioners and other appliances are interruptible.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.77**

**Responding Witness: John K. Wolfe**

Q-2.77. On p.84 of Vol. I, it states: "VVO will also support implementation of conservation voltage reduction (CVR), the intentional lowering of distribution system voltages on targeted system components to reduce overall system demand and produce direct energy savings for customers." Please provide further explanation of CVR, how it operates, its costs and benefits, and what the Company sees as the long-term potential for this strategy.

A-2.77. Conservation Voltage Reduction (CVR) is a technology that can reduce energy consumption with no change in customer behavior or the customer experience. CVR is currently planned for deployment on 120 substations with peak loads greater than or equal to 15 MVA. CVR is implemented by intentionally lowering the voltage on a distribution circuit while keeping end use voltages along the entire circuit within an acceptable tolerance band (114-126 volts as defined by ANSI C84.1). Conservation then occurs on the circuit when certain end-use loads draw less power. Without automated metering infrastructure (AMI), CVR savings are much harder to achieve because the operation would depend on estimates of voltage along a circuit, which can be inaccurate due to a number of factors.

In a simplified situation, power savings is calculated using a combination of Ohm's Law and a power calculation as shown below.

Ohm's Law: $Voltage = Current * Resistance$
Power: $Power = Voltage * Current$

Since the resistance of a load typically remains constant, lowering the voltage also lowers the current. Lowering both the voltage and current results in lower power consumption. However, not all electrical loads respond the same to voltage reductions.

AMI is critical for providing the information that is needed to reliably implement CVR. Connected loads can be damaged if voltages fall outside the upper or lower limits of the ANSI-specified tolerance band. With voltage data for every customer, AMI provides the feedback needed to control voltage to lower portions of the tolerance band without jeopardizing reliability or power quality for customers.

In the Companies' business plan, CVR benefits were quantified based on direct fuel savings due to lower energy consumption. Once fully implemented, the Company expects to achieve approximately 205 GWh of energy savings annually. These savings have a 2020 NPVRR of $48.6 million over the 30 year study period (2021-2050).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.78**

**Responding Witness: John Bevington**

Q-2.78. Regarding Nonresidential Rebates Programs, on p.95 of Vol. I, it states: "This program is offered to all nonresidential class customers. The objective is to identify energy efficiency opportunities for customers and assist them in the implementation of these identified energy efficiency opportunities via incentives. The incentives are available for both prescriptive and custom measures, as well as LEED certifications and new construction that exceeds the current building code."

a. List all measures implemented from 2018 - 2021 with the following information:
   i. Measure / action implemented
   ii. Cost of measure to customer
   iii. Amount of incentive provided by the Company
   iv. Annual energy and demand savings of measure
   v. Process used to determine Measure and Incentive amount

b. Please explain the process used to determine what measure will be incentivized for a customer. What Measurement & Verification processes are used to confirm that Measures are installed correctly and perform as expected? Are installations third-party verified?

c. What is the annual budget for the Nonresidential Rebate Program and the average expenditure per participant? How many customers received incentives each year from 2018 - 2021?

A-2.78.

a. See the attached file for the detailed response but note that item "ii" is not available. For subpart v, the detailed process used to determine the measures and incentive amounts was described and performed by Cadmus as part of the 2017 DSM Filing, Case No. 2017-00441, Exhibit GSL-2. Due to its very large file size, a link from the Commission site is provided here:

https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf. Also refer to the Potential Study included as Exhibit GSL-3 in the case as it was performed by Cadmus and heavily informed the analysis. Using the link above, one can find this document starting at page 261 of 529.

b. See the response to part a above. In order to verify equipment is actually installed and utilized, the Companies' business partner, Franklin Energy, performs the necessary independent verifications (including virtual and on-site) with the customers.

c. The average annual budget for the program for the period 2019-2025 is approximately $2.7 million. The average rebate paid per customer is $1,031. The number of customers who received a rebate by year (determined by their unique Contract Account) is as follows:

| Year | Number of Customers |
|---|---|
| 2018 | 1,127 |
| 2019 | 1,162 |
| 2020 | 965 |
| 2021 | 1,068 |

The attachment is being provided in a separate file in Excel format.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.79**

**Responding Witness: John Bevington**

Q-2.79. Why does the Company propose to continue offering energy efficiency rebate programs for non-residential customers but does not propose extending these rebates to residential customers?

Q-2.79. The Companies are not making any DSM-EE proposals in this proceeding. The Companies currently offer the Nonresidential Rebates Program as part of their Commission-approved 2019-2025 DSM-EE Program Plan because it had favorable cost-benefit test scores.[28] The Companies did not include a continuation of their Residential Rebates Program in the 2019-2025 DSM-EE Program Plan because of its lack of cost-effectiveness.[29]

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[28] Case No. 2017-00441, Order (Ky. PSC Oct. 5, 2018).
[29] *See* Case No. 2017-00441, Direct Testimony of Gregory S. Lawson, Exh. GSL-1, Section 1.2, pages 9-11 (Dec. 6, 2017).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
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**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.80**

**Responding Witness: Stuart A. Wilson**

Q-2.80. On p.9 of Vol. I, the Companies note that they experience peak demand in summer and winter, and that the increasing use of electric heating increases the frequency of winter peaks. There is also a societal shift towards the electrification of heating systems, as another strategy for decarbonizing the energy system. With this in mind, please provide all studies and analysis performed by the Companies concerning incentivizing the use of high-efficiency heat pumps, including units known as "mini-split heat pumps," for both residential and nonresidential customers.

A-2.80. The Companies have not performed such studies.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.81**

**Responding Witness: John Bevington**

Q-2.81. In August of 2020, KU made a presentation to Mountain Association regarding a potential on-bill tariff, including a slide referencing their "On-Bill Tariff Analysis – 'Measure View" that included some of their assumptions and the results of their preliminary "cost/benefit tests for normal weather." Please provide the full set of assumptions that the companies used for these analyses, as well as the full analyses and results of all of the cost/benefit tests for which scores were presented. (Utility test: 3.57, TRC test: 0.26, RIM test: 0.16, RIM net fuel test: 0.16, Societal Test: 0.26, and Participant test: 2.09.)

Q-2.81. See the attached files, which contain the assumptions, cost-effectiveness scores, and the slide deck from that meeting.

The attachment is being provided in a separate file in Excel format.

# LG&E/KU and MACED Opportunities

August 24, 2020

LG&E KU
PPL companies

# Agenda

- **Welcome / Intros**
- **John Bevington**
- **Update on On-Bill Tariff Financing**

# On-Bill Tariff

## Process path needed to implement new offering:

For **DSM** items, in *parallel paths*, we:

- Navigate regulatory and legal constraints
- Analyze various costs and benefits of offering, as well as timeframe to launch, then compute cost/benefit calculations for the offering (i.e. California Tests)
- Determine operational constraints for offering
- Weigh customer benefits / impacts

*Once these parts are complete, we then:*

- Prepare "Filing" for submission
- File for PSC Regulatory approval
- If approval received, ***LAUNCH…***

# On-Bill Tariff continued…

## Process path needed to implement new offering:

***Similar process, but few key differences***

For **non-DSM** items, in *parallel paths*, we:

- Navigate regulatory and legal constraints
- Analyze various costs and benefits of offering, as well as timeframe to launch, then determine ROI or applicable metric(s) for evaluation
- Determine operational constraints for offering
- Weigh customer benefits / impacts

*Once these parts are complete, we then:*

- Prepare "Filing" for submission
- File for PSC Regulatory approval
- If approval received, ***LAUNCH…***

# On-Bill Tariff Analysis – "Measure View"

*Let's look at how the single measure "performs" in a cost/benefit test*

**Example**:
- Rate: KU Residential Service (RS)
- Single $7,500 project with $3,750 down payment
- 7-year term at 3% ➔$50/mo payment
- Payment offset by savings of 553 kWh/mo
- Audit fee of $575 paid by utility to auditor/organization
- No other admin fees assumed (for now…)

***Note: Typical DSM program planning period of 7 years or less can limit the term period of the loan which could exceed the life of the program.***

- Preliminary Run in DSMore Cost/Benefit Model:

| Cost / Benefit Tests For Normal Weather | |
|---|---|
| | Cost Based |
| Utility (PAC/UTC) Test | 3.57 |
| TRC Test | 0.26 |
| RIM Test | 0.16 |
| RIM (Net Fuel) | 0.16 |
| Societal Test | 0.26 |
| Participant Test | 2.09 |

**Notes:**
**Test scores above 1 are passing**
**Participant Test score is above 1**
**Key PSC test: TRC**
**Utility Test is good, but…**

***What do these scores mean?***

# Test Score Details - Preliminary

| Present Values (PVs) of Costs and Benefits Per Test | |
|---|---|
| | Cost Based |
| **Utility (PAC/UTC) Test** | |
| Avoided Electric Production | $2,052.00 |
| Avoided Electric Production Adders | $0.00 |
| Avoided Electric Capacity | $0.00 |
| Avoided T&D Electric | $0.00 |
| Avoided Ancillary | $0.00 |
| Avoided Gas Production | $0.00 |
| Avoided Gas Capacity | $0.00 |
| Total | $2,052.00 |
| Administration Costs | $575.00 |
| Implementation / Participation Costs | $0.00 |
| Other / Miscellaneous Costs | $0.00 |
| Incentives | $0.00 |
| Total | $575.00 |
| Reduced Arrears | $0.00 |
| Test Results | 3.57 |

| **Participant Test** | |
|---|---|
| Incentives | $0.00 |
| Participant or Unit Costs (Gross) | $7,565.66 |
| Participant or Unit Tax Credits (Gross) | $0.00 |
| Bill Savings (Electric) (Gross) | $15,828.71 |
| Bill Savings (Gas) (Gross) | $0.00 |
| Total | $15,828.71 |
| Test Results | 2.09 |

| **TRC Test** | |
|---|---|
| Avoided Electric Production | $2,052.00 |
| Avoided Electric Production Adders | $0.00 |
| Avoided Electric Capacity | $0.00 |
| Avoided T&D Electric | $0.00 |
| Avoided Ancillary | $0.00 |
| Avoided Gas Production | $0.00 |
| Avoided Gas Capacity | $0.00 |
| Total | $2,052.00 |
| Administration Costs | $575.00 |
| Implementation / Participation Costs | $0.00 |
| Other / Miscellaneous Costs | $0.00 |
| Total | $575.00 |
| Reduced Arrears | $0.00 |
| Participant or Unit Costs (Net) | $7,239.27 |
| Participant or Unit Tax Credits (Net) | $0.00 |
| Environmental Benefits | $0.00 |
| Other Benefits | $0.00 |
| Total | $0.00 |
| Test Results | 0.26 |

# WeCare Outreach

- Estimate KU has over 120,000* active residential accounts in the MACED service territory
- Depending on definition of Limited Income (10% to 25% of total), this could be approximately 12,000 to 30,000 eligible accounts for WeCare offering
    - ➢ These customers could be just outside of our typical outreach areas (primarily Lexington and Louisville)

***Note: Active residential accounts as of May 2020**

# WeCare Outreach - PROPOSAL

- Develop rack cards for MACED and their partners to share with KU customers
  - One card that covers every utility/co-op customer?

- Work with MACED to:
  - Identify and engage with multi-family properties where tenants may qualify for program
    - Can be either residentially or commercially metered!
  - Identify and engage local entities for increased awareness of WeCare as well as other DSM offerings (i.e. Business Rebates Program)

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.82**

**Responding Witness: John Bevington / Robert M. Conroy**

Q-2.82. Ouachita Electric in Arkansas credited robust investments in PAYS (Pay as you Save programs) and DER's when they delivered a 4.5% rate decrease to their owner-members in 2020. How would a robust PAYS-based inclusive utility investment program impact the companies' cost of service? How would a robust plan to incent DER's impact the companies' cost of service?

A-2.82 Regarding "a robust PAYS-based inclusive utility investment program," it is impossible to know the cost-of-service impact of such a program without far greater specificity.

What the Companies have analyzed regarding PAYS programs is not promising from a cost-of-service perspective. In the Companies' most recent review of a PAYS-type program and in discussions with Mountain Association in summer 2020, the preliminary cost-effectiveness of such an offering did not score above 1 in the Total Resource Cost (TRC) Test. Further, the operational, legal, and regulatory issues around implementing such an offering were highly complex especially as it relates to mitigating the risk of default and whether the risk of default stays with a customer or the property where the retrofits were made. All of these issues, as well as others, could have cost-of-service impacts.

That notwithstanding, the Companies committed in their 2020 rate cases to "engage in a stakeholder process using the Utilities' existing DSM Advisory Committee for their next DSM filings to consider and evaluate … an on-bill financing program."[30]

Regarding a robust incentive plan for DERs, again it is impossible to know the cost-of-service impact of such an incentive plan without far greater specificity.

[30] Case Nos. 2020-00349 and 2020-00350, Order Appx. A at 15, para. 5.6 (Ky. PSC June 30, 2021).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
**Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.83**

**Responding Witness: Stuart A. Wilson**

Q-2.83. In reference to the "2021 RTO Membership Analysis" (Vol. III, pp.84- 140), on p.103 it states, "The High Case uses assumptions most supportive of RTO membership, such as lower administration costs, higher energy and capacity prices, and lower transmission expansion costs."

a. Are we correct that higher energy and capacity prices are deemed favorable if the Companies are selling energy and capacity into the RTO?

b. In cases where RTO energy and capacity prices are very low, would that provide an opportunity to provide lower cost power to customers?

c. Did the Companies evaluate RTO membership through the lens of meeting aggressive carbon emission reduction goals? Was enabling greater and more rapid reductions in carbon emissions included as a benefit among the measures used to evaluate RTO membership? Please discuss how RTO membership could enable the Companies to meet such goals.

d. How would the RTO analysis be changed if achieving more aggressive carbon emission reduction goals were included as a benefit among the other metrics used to evaluate RTO membership?

e. How did the Companies include Louisville Metro's 100% Renewable Energy Commitment into their RTO Membership Analysis? Please provide all data and workpapers associated with this analysis.

A-2.83.

a. The net favorability of such a scenario would be determined by the situations' specific circumstances (regarding load, energy and capacity prices, fuel prices, unit availability, etc.) and cannot be generalized in this manner.

b. See the response to part (a).

c. $CO_2$ emissions reductions were discussed in Section 3.3.2 of the *2021 RTO Membership Analysis*, however the level and pace of $CO_2$ emissions reductions was not evaluated in the RTO membership analysis.

d. The Companies have not performed this analysis.

e. This was not included in the analysis.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.84**

**Responding Witness: John Bevington / Stuart A. Wilson**

Q-2.84. In PSC ORDER 20210514 in case number 2020-00174 (Kentucky Power), the commission identified several principles that should be followed in evaluating distributed generation. These include: Evaluating eligible generating facilities as a utility system or supply side resource; Treating benefits and costs symmetrically; Conducting forward-looking longer term and incremental analyses; Avoiding double counting; and Ensuring transparency. Please indicate:

a. How the companies have followed these principles when planning for the role of distributed generation in the planning period.

b. What avoided costs have been incorporated into the analyses of distributed generation? For example, have any of the following been included: avoided energy cost, ancillary services cost, generation capacity cost, transmission capacity cost, distribution capacity cost, carbon cost, environmental compliance cost.

c. How have the companies applied any of these same principles and avoided costs to evaluation of any of its DSM (including energy efficiency) programs?

d. Have the companies considered jobs benefits of distributed generation or energy efficiency programs?

A-2.84. The premise of this request is flawed. The Commission order to which the request refers does not discuss general principles for "evaluating distributed generation"; rather, it addresses "best practices for compensating eligible customer-generators," i.e., setting compensation rates for net metering customers.[31] The IRP process and this proceeding do not concern net metering compensation; therefore, the Companies did not explicitly incorporate in their IRP analysis net metering compensation principles from the cited Kentucky Power Company rate case order. The Companies' discussion of how they addressed distributed generation is at IRP Volume I, pages 5-27 through 5-30. Regarding DSM, see the response to PSC 1-4.

[31] Case No. 2020-00174, Order at 21 (Ky. PSC May 14, 2021).

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

**Response to Joint Intervenors'**
**Supplemental Request for Information**
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**Case No. 2021-00393**

**Question No. 2.85**

**Responding Witness: David S. Sinclair**

Q-2.85. Page 36 In figures 5-14 to 5-15 the companies illustrate how distributed generation will only impact energy requirements in the "high scenario when a new federal law is assumed to eliminate the 1% cap on total installed net metering capacity'. Without this cap elimination DG will not grow sufficiently to reduce companies' energy requirements.

a. Is it not in the public interest to reduce the energy requirements the company needs to meet? So would it not be in the public interest for the company to push for expanded DG?

b. Can the companies analyze the cost savings to the companies in this high solar vs. base solar scenario (e.g. using the principles and avoided cost categories set forth in The NSPM-DER and in PSC order in Kentucky Power Company Case No. 2020-00174)?

A-2.85. The statement, "Without this cap elimination DG will not grow sufficiently to reduce companies' energy requirements," is incorrect. The IRP states, "Figure 5-14 and Figure 5-15 show the impact of distributed solar generation on peak energy requirements in the base and high forecast scenarios, respectively. The impact is small in the base forecast but much larger in the high forecast." Any amount of distributed generation affects energy requirements; on the whole, more distributed generation will have a larger effect on energy requirements.

a. It is not the Companies' role to say how much energy use is in the public interest. Also, the question is impossible to answer without greater specification, beginning with a clear definition of "the public interest."

b. The Companies can conduct a wide variety of analyses.

**LOUISVILLE GAS AND ELECTRIC COMPANY**
**KENTUCKY UTILITIES COMPANY**

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**Supplemental Request for Information**
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**Case No. 2021-00393**

**Question No. 2.86**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.86. In section 8.3, the companies discuss a variety of efforts they will be making to integrate renewables, but they propose a small percentage of renewables in their 15-year plan, and a small amount of battery storage that might address the frequently mentioned concern related to lack of dispatchability of renewables. On pages 14 and 15 of pdf of Volume III, the companies show that the capital cost of 4 hour battery storage and SCCT's will be roughly equal by 2030 (similarly, as shown on page 18 of pdf, Volume III, by 2031 the LCOE of batteries is slightly below that of SCCTs):

a. Expand on why the companies are waiting until 2035 to add new battery storage while adding new SCCT in 2028.

b. Expand on why such a small amount of battery storage (200 MW) is being added at all, especially in comparison to the 1320-1488 MW of SCCT.

c. Do the companies incorporate environmental compliance costs, carbon costs, or carbon or methane emissions data in comparing the cost benefits of batteries and SCCT?

d. Explain how the companies consider battery storage and solar jointly in their planning. Explain the specific relationship between solar planning and battery planning. How are the cost benefits calculated of solar and battery storage considered in combination?

A-2.86. The Companies disagree with the characterization of the percentage of renewables in their 15-year plan as "small." In 2020, 3.4% of total U.S. electricity generation was from solar resources.[32] In the Companies' base load, base fuel prices scenario, solar energy is almost 18% of total generation by the end of the 15-year period.

[32] https://www.nrel.gov/docs/fy22osti/81325.pdf

a. SCCT capacity is added first because it is lower cost. The LCOE for 4-hour battery storage in 2022 assuming a $25/MWh charging cost is $150.59/MWh, which is 20% higher than the LCOE for SCCT in 2022 of $125.18/MWh assuming the mid natural gas price forecast. The Companies chose to optimize the generation portfolio in 2035 partly to evaluate battery storage at a lower cost compared to SCCT. However, even with this assumption, a relatively small amount of battery storage was selected.

   The Companies also reiterate that the IRP is not a commitment to a particular capacity acquisition, replacement, or retirement program, but rather is a snapshot analysis of various means of serving load safely, reliably, and economically across numerous possible futures. The Companies would evaluate available market options before committing to any additional resources.

b. The Companies modeled cost and operating characteristics for both battery storage and SCCT in PLEXOS for the Long-Term Resource Planning Analysis. While the two technology options have similar costs in 2035, SCCTs can produce energy around the clock if needed, while 4-hour battery storage can produce 100 MW of energy for up to 4 hours. Despite similar or slightly higher capital costs, the additional operating flexibility of SCCTs causes them to be lower cost than 4-hour battery storage.

c. See the response to PSC 2-1 (b).

d. See the response to SREA 1-7.

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**Question No. 2.87**

**Responding Witness: Stuart A. Wilson**

Q-2.87. Have the companies done or planned research into long duration storage such as pumped hydro storage? Please give details.

A-2.87. See Section 2.1.3 on page 7 of the *2021 IRP Resource Screening Analysis*. The Companies continue to monitor advances in other forms of long-duration energy storage through participation in the Electric Power and Research Institute (EPRI), energy storage research program, as well as with the University of Kentucky Center for Applied Energy Research (CAER). The Companies are currently evaluating options for federal research funding for a vanadium redox flow battery, or a hydrogen battery, to store energy generated from renewable power over the longer term. The Companies also participate in the EPRI Low-Carbon Resources Initiative (LCRI), focusing on identifying, developing and demonstrating affordable pathways to economy-wide decarbonization. LCRI seeks advances in a variety of low-carbon electric generation technologies and low-carbon energy carriers, such as hydrogen, synthetic fuels, and biofuels. The LCRI Power Generation subcommittee is focused on fuel cell development powered by low-carbon energy carriers such as hydrogen that can be incorporated into a hydrogen battery system.

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**Question No. 2.88**

**Responding Witness: Counsel / Robert M. Conroy**

Q-2.88. We would like to see a detailed analysis of the costs of dealing with regulations:

a. What are the companies' costs of trying to head regulations off (analysis, lobbying, legal actions).

b. What are the companies' costs of responding to regulators (penalties, ameliorative actions).

c. How are these costs reflected in customer bills and in reduced shareholder dividends?

A-2.88. This request is objectionably vague, irrelevant, and argumentative; nothing this request asks could be relevant to the Companies' IRP or the matters addressed in the Commission's IRP regulation, and nothing this request asks could reasonably lead to the discovery of relevant information. Notwithstanding its irrelevance, the Companies note that their rates do not include recovery of lobbying costs.

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**Response to Joint Intervenors' Supplemental Request for Information Dated March 4, 2022**

**Case No. 2021-00393**

**Question No. 2.89**

**Responding Witness: John K. Wolfe**

Q-2.89. Please supply more details on required new investments in the grid:

a. to provide enhanced security against cyber-attacks,

b. to accommodate rooftop solar, solar arrays and other distributed sources,

c. to maintain reliability in extreme weather.

A-2.89.

a. As part of the Companies' strategic cyber security plan, SEL-3620/3622 gateways are being installed in every substation that has IP connectivity. This device utilizes a deny-by-default firewall and functions as a password management system.

Instead of utilizing default device passwords, an employee's company network user account and log-in credentials will be used so that access credentials can uniquely identify an individual. All user access will be logged and monitored inside the security gateway. The interactive password management system ensures quality complex passwords are being generated for the relays. In the case of employee termination, the password management system will de-register the user account therefore removing access and protecting the system. Additionally, a Business to Business (B2B) VPN connection will be utilized for the substation devices to promote segmentation between production networks and operations (OT) networks throughout the organization.

Asset information management systems will be used as a central repository for connected devices (relays and RTUs) so that an OT Asset Inventory is maintained for those assets deemed a cybersecurity risk to OT system operations in EDO. These central repositories will store configurations of connected devices (relays, RTUs, and security gateways).

An asset firmware management procedure is in place to address installation of firmware updates for all devices. On a quarterly basis, Protection and Control Engineering will work with the hardware vendors to review all firmware version updates. Engineering will determine the criticality of each firmware update bulletin and work with Protection and Control Group Leaders to establish timeline for updates to be implemented. High criticality firmware updates will require devices to be updated immediately. Lower criticality firmware updates will be addressed as soon as operationally possible.

Finally, all ports and services for substation devices will be turned off if they are not in use.

b. The Companies are currently making significant investments in their centralized grid operations strategy. Centralized Grid Operations defines Distribution Operations' organizational structure, business processes, technologies, and decisional hierarchy for monitoring, controlling, planning, and operating the electric distribution system. This operational approach is enabled and advanced by the Companies' recent and planned investments in operations, information, and communications technologies, including those technologies being deployed in the Distribution Automation, SCADA expansion, substation relay modernization, and crew technology mobilization capital programs. These technologies equip responsible personnel with more granular and near immediate monitoring and awareness of the electric grid, further enabling critical decision-making regarding system operations during normal, abnormal, or emergency conditions. These investments in grid modernization also help accommodate additional rooftop solar and other distributed resources on the system.

Distributed Energy Resources, expanded electrification of transportation, and grid-interactive customer assets all pose new challenges to operation and performance of the electric grid. Distributed Energy Resources include small and decentralized customer-owned electric generation resources or other "behind the meter" technology that is connected to the grid at the distribution level. These systems result in two-way power flow insofar as customers with Distributed Energy Resources both provide to and take power from the electric distribution system. These added system challenges will expand the need for visibility and control to support advanced system planning and ensure high levels of reliability and power quality for customers.

The Companies' Centralized Grid Operations strategy includes investments in additional connected field devices, through Distribution Automation and substation SCADA expansion, and enhancements to the Companies' SCADA technology platform that allow visibility into grid operations. These investments ensure that the Distribution Control Center can monitor and manage system disturbances quickly. Enhanced field devices will make certain that the Companies' protection and control information management systems are resilient and designed to quickly manage outages and minimize system impacts now and into the future, when more dynamic operating conditions and challenges will exist. These connected devices also increase data availability across all levels of the grid, enhancing the Companies' overall system planning processes to account for two-way power flow.

Finally, implementation of Volt/VAR optimization (VVO) will allow the utilities to better optimize system performance, minimize technical system losses, and increase hosting capacity for DER on the system.

c. The Companies have made substantial investments in system reliability and resiliency programs since 2010 in response to the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm. These two storms caused the most significant system damage in the Companies' history and had residual impacts to system reliability. System reliability and resiliency programs along with design standard improvements allow LG&E and KU's system to perform well in adverse weather conditions.

EDO's system hardening program focuses on rear easement hardening, conductor upgrades, and circuit relocations. Generally, rear easement hardening involves the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Pole Inspection and Treatment Program (PITP) provides annual inspection, treatment, reinforcement, and replacement, where necessary, of LG&E and KU's wooden distribution poles. The PITP provides a systematic and focused approach to prolonging the service life of poles through a pole-by-pole inspection and assessment, and execution of condition based corrective actions where deficiencies are identified. Updated distribution construction standards such as larger pole classes, increased conductor spacing, and storm guying in select locations also place an emphasis on system resiliency.

LG&E and KU also employ an integrated vegetation management plan that incorporates use of manual, mechanical, or chemical techniques to control undesirable vegetation and includes natural or directional pruning, tree removal, or application of environmentally safe herbicides. The routine cycle program provides for maintenance of a scheduled proactive circuit cycle – on a five-year or less average – in harmony with reactively addressing circuits where tree related outages and reliability performance do not meet customer expectations. The Companies' hazard tree program addresses trees that are predisposed to failure which could contact a distribution conductor.

The Companies have realized a 35% improvement in interruption frequency including all outages when comparing the current 5-year period (2017-2021) average versus the 5-year period before more aggressive investment (2005-2009).

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**Question No. 2.90**

**Responding Witness: Eileen L. Saunders / John K. Wolfe**

Q-2.90. Will the companies offer strategies to enhance the benefits of grid edge resources, that may also reduce capital cost by customers to invest in those, such as interconnected renewables, timed vehicle charging and storage? ConnectDER (https://connectder.com), manufactures a collar designed to fit between the revenue meter and the meter base for a convenient interconnection location for grid edge resources. This could empower both companies and customers with enhancing the value of grid edge resources and reducing the customer's cost to install grid edge resources by conveniently interconnecting at the meter base instead of facing complexities and added costs that may arise from connections at the customer's load distribution panel. Will companies partner with ConnectDER and provide the collar to customers wishing to interconnect resources to companies or allow ConnectDER collar products to be installed by their customers between the meter base socket and the meter? If not, please explain the rationale fully.

A-2.90. The Companies evaluated the ConnectDER meter collar a few years ago and continue to monitor the technology as it evolves. Multiple vendors now offer similar devices for interconnecting DER at the meter, but the Companies do not currently allow meter collar or meter extension devices to be utilized for interconnection of grid-edge devices. It is recognized that these devices do provide potential benefits such as monitoring and control of grid edge assets, but there are some risks associated with them.

Because the meter collar is installed between the meter and the meter base, access to the meter base for routine inspections or service is more difficult. Not being able to easily access the connections inside the meter base during routine meter inspection work could lead to issues with service restoration or troubleshooting. Although owned and maintained by the customer, all meter bases, enclosures, and compartments are under the exclusive control of LG&E and KU and will be sealed by LG&E and KU for safety and security. Access to the meter base or any other sealed enclosures without LG&E and KU's authorization is prohibited. Because the seal must be removed to install the meter collar, tampering is also a potential concern. During routine work, it is possible to compromise any internal and external connections or even physical fitment of the collar. If at some point any of this results in property damage or fire hazard, there are liability and customer experience concerns at stake. Additionally, this requires specific training for all field services personnel to be able to deal with new technologies such as these collars.

Finally, the ConnectDER collar is only rated for DER installations up to 11.5kW. This would exclude a majority of installations as many exceed this rating. Additionally, the collar is only rated for 180 amps of continuous service so therefore it cannot be used on any service above 200 amps.

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**Question No. 2.91**

**Responding Witness: Stuart A. Wilson**

Q-2.91. Please provide any and all energy burden analysis considered as a part of the Integrated Resource Plan (IRP) process. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

A-2.91. See the response to Question No. 2.8.

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**Case No. 2021-00393**

**Question No. 2.92**

**Responding Witness: David S. Sinclair**

Q-2.92. Please provide any and all strategy screens the Companies applied during the development of the proposed Integrated Resource Plan (IRP) process to advance equity and the outcomes from applying these strategy screens. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

A-2.92. It is unclear to what kind of equity the question intends to refer. The Companies' IRP seeks to satisfy the Commission's IRP regulation, which requires "regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for ***all customers*** within their service areas …."[33] Also, the Companies always seek to treat customers equitably in accordance with KRS 278.170(1):

> No utility shall, as to rates or service, give any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage, or establish or maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions.

See also the responses to Question Nos. 2.8 and 2.13.

[33] 807 KAR 5:058 (emphasis added).

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**Question No. 2.93**

**Responding Witness: David S. Sinclair**

Q-2.93. Please provide data on the impact of electrifying large sectors of the U.S. economy over the period of the proposed Integrated Resource Plan (IRP) and the implications for low-income customer affordability and access. What steps are the Companies taking to ensure equitable distribution of benefits and costs on low-income customers? Please provide any and all analysis. Please provide data by census tract and zip code.

A-2.93. See the response to Question No. 2.8.

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**Case No. 2021-00393**

**Question No. 2.94**

**Responding Witness: Counsel / Eileen L. Saunders**

Q-2.94. Please provide the following data, and any and all internal analysis and discussion materials, on how this influenced the preparation of the proposed Integrated Resource Plan (IRP) and how COVID-19 pandemic data impacted the analysis in anticipating future pandemic instability:

a. Please provide data for the number of people who are eligible for gas disconnection by census tract. Please provide data for the number of people who are eligible for electric disconnection by census tract

b. Please provide data on the number of people who are behind on their gas payments by census tracts. Please provide data on the number of people who are behind on their electric payments by census tract.

c. Please provide data on the average amount owed on past due bills by census tract.

d. Please provide data on the number of people who have a signed repayment plan by census tract.

e. Please provide data on the number of people who are behind on their payments, but do not have a signed payment plan in place by census tract.

f. Please provide data on the number of people who have a signed payment plan who are current on that payment plan by census tract.

g. Please provide data on the number of people who have a signed payment plan who have missed one or more payments by census tract.

h. Are the people who have missed one or more payments on their payment plan included in the overall number of people who are eligible for disconnection?

i. Please provide data on the number of people who have received support from pandemic utility assistance programs by census tract.

j. Please provide data on the amount of money received by the Companies from pandemic utility assistance programs.

k. How many households have the companies disconnected from electrical service since February 2020? Including multiple disconnections to households, how many total disconnections have been carried out?

l. What was the average length of these disconnections?

m. Which zip codes (or census tracts in Louisville/Lexington) had the highest disconnection rates?

n. How much would it have cost to forgive those arrearages instead of making those disconnections?

A-2.94. All parts of this request seek information that is irrelevant to this proceeding, and none of the requested information could reasonably lead to the discovery of relevant information. According to the Commission's IRP regulation, the purpose of an IRP "regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas …."[34] Therefore, gas service information is not relevant to this proceeding. Likewise, service disconnections, late payments, and payment plans are not relevant to this proceeding.

[34] 807 KAR 5:058.

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**Question No. 2.95**

**Responding Witness: Eileen L. Saunders**

Q-2.95. In their 2017 report "Lights Out in the Cold: Reforming Utility Shut-Off Policies as If Human Rights Matter," the NAACP "calls for concrete action toward establishing policies that protect the well-being of all utility customers and the eventual elimination of utility disconnections." They also provide "a collection of true stories about real people whose lives were cut short, or nearly cut short, by utility companies who were willing to pull the plug to protect profits," and go on to state that "the establishment of a universal right to uninterrupted energy service would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages."

But according to the Legal Aid Network of Kentucky, for ratepayers that are facing disconnection, "a 30-Day Extension of Service Must Be Granted if:

- Member of Household is Ill: The customer brings in, before the shut-off date, a "Certificate of Need" statement signed by a doctor, nurse, or public health official, saying that cutting off service would harm a member of the household who is ill. Follow-up requests for extensions must include not only the doctor's statement but also an agreed partial payment plan.

- Notice Goes To Low-Income Household between November 1 & March 31: Customer brings in, before the shut-off date, a statement from their local office of Community Based Services that they qualify for the heating assistance program or their income is at or below 130% of poverty. If the customer can work out a payment plan which will catch up their bill by no later than October 15, they can't be disconnected."

- What concrete actions are the companies taking to ensure and increase universal access to electricity, especially to underserved communities such as low-income households and communities of color? What policies do you have in place that go above and beyond the legal rights noted by the Legal Aid Network?

A-2.95. See the responses to Question Nos. 2.8, 2.13, and 2.94. The Companies reiterate that they seek to provide safe and reliable service at the lowest reasonable cost, and they do so on a non-discriminatory basis in accordance with KRS 278.170(1).

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**Question No. 2.96**

**Responding Witness: Eileen L. Saunders**

Q-2.96. What was the amount collected in late fees for each of the calendar years 2018 – 2021? How much do you expect to collect in 2022? How much (as a percentage of revenue) do late fees contribute to the companies' budgets? How do these numbers compare nationally?

A-2.96. See the response to Question No. 2.94.

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**Question No. 2.97**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-2.97. In the IRP filings, the companies state: "In 2021, EPA began emphasizing the use of their environmental justice screening tool ("EJ Screen") when community or project stakeholders have concerns about impacts on a community regarding issues related to environmental justice. However, as of the date of this IRP, there is no prescribed guidance on data interpretation nor any defined actions that should be taken based on the data provided by use of EJ Screen. Therefore, the Companies will continue to utilize existing siting processes until change is prompted by local, state, or federal drivers. Although not actively utilizing the EPA's EJ Screen, the Companies consider environmental and economic factors in assessing and planning development activity."

a. Please elaborate in detail how you consider environmental and economic factors in planning and development. Specifically, how do you identify and consider impacts on low-income households and communities of color?

b. Would it be beneficial to begin working with the screening tool to identify inequities in advance of directives on how to address them? Will you continue to ignore these inequities unless forced to address them by a regulatory entity?

c. We know that low-income and communities of color are disproportionately impacted by energy production and energy burden. How do you consider these impacts in your planning and development processes? How do you prioritize DSM and DER's that lower energy bills in environmental justice communities?

A-2.97. See the responses to Question Nos. 2.8, 2.13, and 2.94. The Companies consider environmental and economic factors in planning and development to the extent they might affect the Companies' ability to provide safe and reliable service at the lowest reasonable cost to all customers on a non-discriminatory basis in accordance with KRS 278.170(1).

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**Question No. 2.98**

**Responding Witness: Eileen L. Saunders**

Q-2.98. How are the companies helping low-income households and communities of color access DER's to lower their energy bills? Are the companies encouraging more accessible and equitable solar policy like the monetization of tax incentives, virtual net metering, third-party ownership, etc? If not, why?

A-2.98. The Companies offer net metering service and the Solar Share Program on a non-discriminatory basis in accordance with KRS 278.170(1). See also the responses to Question Nos. 2.8, 2.13, and 2.88.

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**Case No. 2021-00393**

**Question No. 2.99**

**Responding Witness: John Bevington**

Q-2.99. Please provide data on programmatic DSM charges and disbursements (incentives, rebates, and weatherization assistance) for low-income and communities of color, either by census tract or zip code.

A-2.99. See the responses to Question Nos. 2.8 and 2.13.

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**Case No. 2021-00393**

**Question No. 2.100**

**Responding Witness: David S. Sinclair**

Q-2.100. How have the companies engaged stakeholders, including residential customers, in the development of this IRP?

A-2.100. See the response to SREA 1-4(a).