COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	**))))))))**	**CASE NO. 2022-00402**

TESTIMONY OF ANNA SOMMER

ON BEHALF OF JOINT INTERVENORS METROPOLITAN HOUSING COALITION, KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY AND MOUNTAIN ASSOCIATION

July 14, 2023

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I. INTRODUCTIONS & QUALIFICATIONS

Q. Please state for the record your name and business address.

A. My name is Anna Sommer. My business address is 30 Court St., Canton, NY 13617.

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

A. I am a Principal at Energy Futures Group ("EFG").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, "Joint Intervenors").

Q. Please describe your educational and professional background.

A. I have worked for twenty years in electric utility regulation and related fields. During that time, I have reviewed over one hundred integrated resource plans ("IRPs") and related planning exercises in jurisdictions all over the country and in Canada. I have reviewed planning modeling based on multiple models including Aurora, Capacity Expansion Model, EnCompass, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, and System Optimizer, and have had formal training on the Aurora, EnCompass, PowerSimm, and Strategist models. Our firm has licensed or is currently licensing Aurora, EnCompass, PLEXOS, SERVM, and Strategist. I have provided expert testimony on resource planning and certificate of need applications in front of utility commissions in Indiana, Michigan, Minnesota, Montana, New Mexico, North Carolina, Puerto Rico, South Carolina, South Dakota, and West Virginia.

I also hold a B.S. in Economics and Environmental Studies from Tufts University, and an

M.S. in Energy and Resources from the University of California, Berkeley. I have also taken coursework in data analytics at Clarkson University and in Civil Engineering and Applied Mechanics at McGill University and participated in the U.S. Department of Energy-sponsored Research Experience in Carbon Sequestration. My resume is attached as Exhibit AS-1.

Q. Have you previously filed expert witness testimony in other proceedings before this Commission or before other regulatory commissions?

A. Yes, I have previously testified before regulatory commissions in Indiana, Michigan, Minnesota, Montana, Puerto Rico, New Mexico, North Carolina, South Carolina, South Dakota, and West Virginia.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1. make recommendations to the Commission for improvements to the Companies' modeling that will result in more fair and equitable analysis of resource choices, capture broader risks, and make their planning efforts more transparent; and
2. present the cost and resource adequacy results from modeling conducted of two additional portfolios, one that includes only one new natural gas combined cycle ("NGCC") facility and one that includes renewables, battery storage, demand-side management and the conversion of Mill Creek 2 to operate on gas.

Q. What are your recommendations to the Commission?

A. I recommend that the Commission direct the Companies to:

1. Develop a stakeholder process that would invite participation in the Companies' planning efforts not just for the IRP but also for other planning and resource acquisition related modeling.
2. Perform a comprehensive climate risk assessment and file it with this Commission.
3. Update their modeling database to include the myriad of potential technologies that would facilitate deep reductions in carbon dioxide emissions.
4. Update their PLEXOS and SERVM databases for the settings described in my testimony and perform further testing of PLEXOS time sampling setting to determine which best represent battery storage dispatch.
5. Begin planning for how they might meet the EPA's fossil fuel carbon rules now and provide that plan to the Commission in their next IRP filing.
6. If one or more NGCC units is/are approved by this Commission, provide regular updates on the project schedules, the negotiations with the EPC contractor and other milestones, and the project cost.

II. THE COMPANIES' MODELING

A. IMPROVEMENTS IN THE COMPANIES' MODELING METHODOLOGY ARE NEEDED

Q. Please describe the Companies' modeling approach for this application.

A. The Companies relied primarily on three models: PLEXOS, PROSYM, and SERVM.

The purpose of each of those models is illustrated in Figure 1.

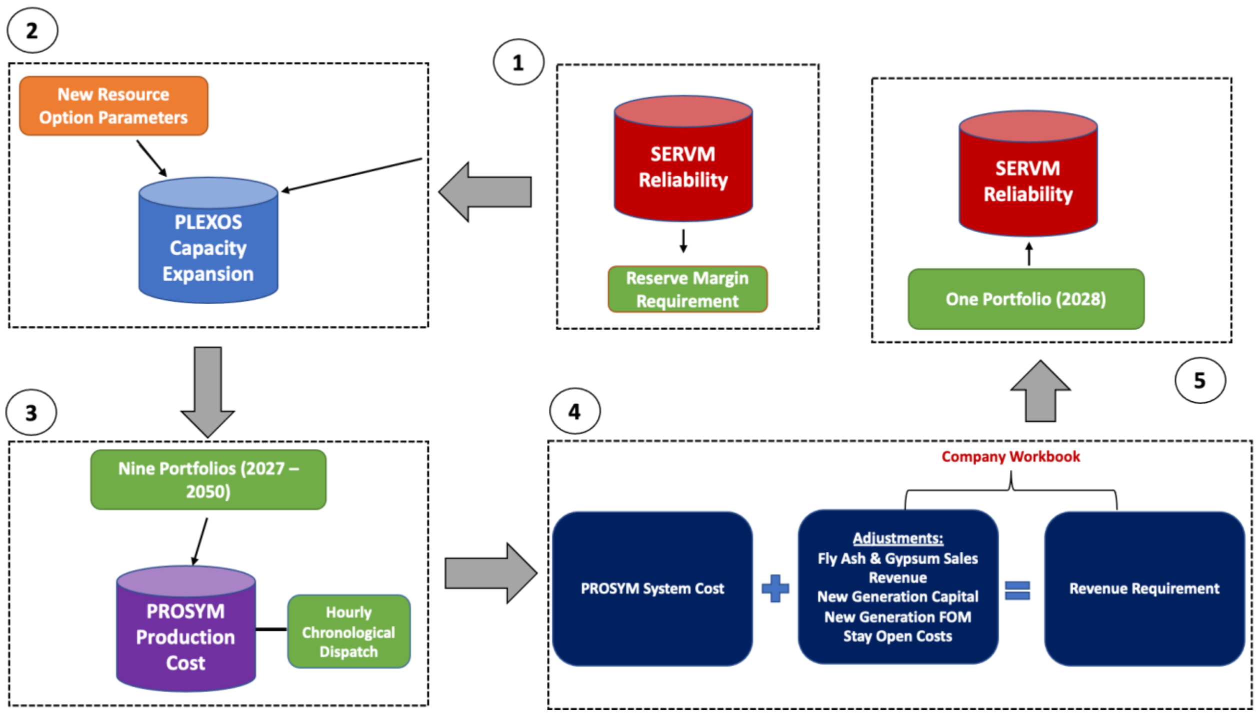

Figure 1. The Companies' Modeling Process

Three key changes to this process from the 2021 IRP are worth noting. First, the Companies are modeling each year of the planning period in PLEXOS, rather than just the last year. Second, the Companies developed a full set of production costs for more than one plan. And third, the Companies evaluated the reliability impact of their preferred plan in SERVM rather than merely relying on the modeled reserve margin to inform the question of whether the portfolio is reliable or not. These three steps are all recommendations that EFG made in our report on the Companies' 2021 IRP. I applaud the Companies for making these important improvements.

Notwithstanding those improvements, the Companies' modeling approach still effectively reduces the plans it evaluates to a single portfolio of resources that I will call the "Companies' Preferred Plan" throughout my testimony. The Companies' Preferred

Plan is partially based on one of the PLEXOS plans, but the Companies add self-build solar, combustion turbine ("CT"), battery storage, and demand response (“DR”) capacity to that plan, and use a combination of cost and reliability results to select all of those resources except the CT as additions to its plan. The Companies never explore creating multiple plans using this same approach or subjecting multiple, significantly different plans to SERVM and iterating on those results to achieve similar levels of reliability. Effectively, the Companies never compare their Preferred Plan to any other significantly different plan on the basis of cost and reliability. The iterations presented in Mr. Stuart Wilson’s testimony focused on the reliability impact of adding resources to the two NGCC plan only.

Q. But does not Table 13 in Exhibit SAW-1 compare nine portfolios on a cost basis, specifically present value of revenue requirements[1]?

A. It does, but the Companies’ Preferred Plan is not among them. And the Companies do not present the SERVM reliability results for any of those plans except Case 1, which serves as the starting point for the Companies’ Preferred Plan.

Q. What would you recommend for future IRPs and CPCN applications?

A. I would continue to recommend that the Companies use just one model for capacity expansion and production cost modeling. PLEXOS is capable of performing these functions, but one of its challenges is that it does not calculate the net present value of system costs or of revenue requirements, which necessitates the use of a spreadsheet to

[1] Direct Testimony of Stuart A. Wilson, In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan, Case No. 2022-00402, (Dec. 15, 2022) (“Wilson Direct”), Exhibit, SAW-1 at 32.

perform this function.

I also recommend that the Company apply the same modeling approach to each portfolio it examines. The Companies stated in Exhibit SAW-1 that "Companies thought it was particularly important to explicitly evaluate other portfolios and compare their economics."[2] I agree with that and would add that it is also important to evaluate multiple portfolios for their reliability and to adjust the portfolios to meet the reliability criteria and then, again, compare their economics. Those are the steps the Companies did not take.

B. ADJUSTMENTS TO PLEXOS ARE NEEDED

Q. Were there also specific changes to the Companies' use of PLEXOS that are needed?

A. Yes. The Companies concluded, on the basis of their initial PLEXOS modeling, that DR (the Companies calls this "dispatchable DSM") is "uneconomical for achieving minimum levels of reliability and meeting the significant need for energy created by the retirement of the three coal units."[3]

The Companies later reverse that conclusion on the basis of their SERVM modeling and say that "adding DSM is the most cost-effective means of enhancing reliability"[4] amongst the resources iterated in SERVM.

I believe this disagreement between the Companies' SERVM and PLEXOS modeling occurs at least in part because the Companies are using a non-chronological

[2] *Id.* at 27.
[3] Wilson Direct at 15, lines 12–14.
[4] Wilson Direct at 33, lines 1–2.

representation of time.

Q. What do you mean by non-chronological representation of time?

A. Optimization models typically used to conduct IRPs such as PLEXOS, Aurora, EnCompass, and others require simplifications in order to achieve a reasonable problem size and find a feasible solution subject to the constraints imposed on the model, e.g., the reserve margin constraint. A typical simplification of capacity expansion modeling is to represent, for dispatch purposes, a subset of the hours in the planning period. Users of PLEXOS, as opposed to Aurora and EnCompass, also frequently use the setting "Partial chronology" which orders load from highest value to lowest value (rather than chronologically). Other chronology settings in PLEXOS – "Fitted" or "Sampled" – apply a chronological approach. The Companies were aware and understood that they were using the load duration curves generated by applying Partial chronology, but they did not seem to test what impact that would have on resource selection. We reran the optimization changing only the chronology to Fitted, which is a chronological representation and the curve fitting period to "day" instead of "month" and PLEXOS did not retire the existing demand response.

Storage may suffer the same problem – but additional testing of these settings is needed to understand what combination of chronology (whether hours are ordered by load or sequentially), the curve fitting period (whether the sampled period per month is a day, week, or month in length), and the number of blocks (how many units of time are in each curve fitting period, e.g., eight blocks per day would imply periods that are more than an hour in length) might influence whether storage is added or not.

C. ADJUSTMENTS TO SERVM ARE NEEDED

Q. Were there also specific changes to the Companies' use of SERVM that are needed?

A. Yes. I have recommendations related to incorporating considerations of incremental unit outages from extreme hot and cold temperatures, including more geographically diverse solar profiles, and modifications to the battery storage settings in SERVM. I will discuss these in further detail in this section.

Q. Does the Companies' modeling of thermal unit outages in SERVM reflect the risk for incremental outages from extreme hot or cold temperatures?

A. No, it does not. The companies have modeled forced and partial outages as occurring with equal probabilities across different temperatures.

Q. Is there a methodology that can be used to include the risk of incremental outages from extreme hot or cold temperatures?

A. Yes, in a report prepared for Advanced Energy Economy ("AEE")[5], Astrapé, the vendor of SERVM, gave a methodology for the evaluation the additional risk of forced outage due to cold and hot temperatures. Using research from Carnegie Mellon University,[6] Astrapé modeled the weather dependent correlation from that report. For cold and hot weather outages, Astrapé was able to develop incremental temperature dependent outage rates in SERVM.

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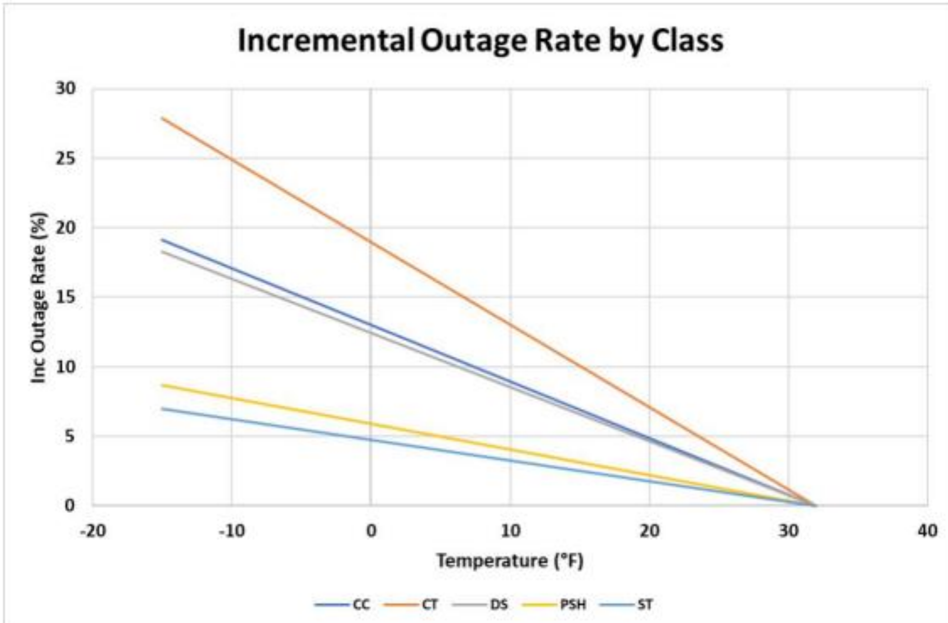
[5] *See* Joel Dison et al., *Accrediting Resource Adequacy Value to Thermal Generation*, Astrapé (Mar. 30, 2022), https://www.astrape.com/wp-content/uploads/2022/10/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf ("Astrapé Report").

[6] *See* Sinott Murphy et al, *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence*, 253 Applied Science 113513 (Nov. 2019), https://www.sciencedirect.com/science/article/pii/S0306261919311870.

Figure 2 below shows an example of the cold weather outage rates across different technologies.



Note: CC = combined cycled, CT = combustion turbine, DS = diesel generator, PSH = pumped storage hydro, and ST = steam turbine

Figure 2. Incremental Outage Rate by Class for Cold Weather[7]

The Companies could apply this methodology as well but through application tailored to the specifics of their resource mix and temperature patterns.

Q. How did the Companies model the hourly profiles for solar resources in SERVM?

A. The Companies used one single profile based on its Brown solar project and applied it to all the solar resources modeled in SERVM.[8] As the responses to the Companies' Request for Proposals ("RFP") indicated, there is significant potential for solar resources to be located in various counties in Kentucky. In order to ensure that the geographic diversity

[7] *See* Figure 2, Astrape Report at 33.
[8] LGE & KU Response to JI Initial Q67.

of solar resources is captured in SERVM, the Companies should develop more than one solar profile to model in SERVM. ~~In addition, the Brown solar project is a fixed axis project, whereas most utility scale solar projects are tracking axis with higher capacity factors.~~

Q. What recommendations do you have related to how battery storage resources were modeled in SERVM?

A. I would recommend two setting changes that are outlined in Table 1 below.

Table 1. Battery Storage Changes in SERVM

Model Setting/Input	Companies Setting	Recommendation
"Schedule Storage Based On"	Market Price	Load
"capmin"	Not specified - Model will default to the unit's capmax	0 MW

With the "Schedule Storage Based On" setting, SERVM will schedule battery storage charging and discharging based on either market price or load. If set to load, then the batteries will discharge during hours when load is the highest and will charge when load is lower. If set to market price, then battery storage schedule will be developed based on the market price and will discharge during high price hours and charge during low price hours which may not align with high load periods. We would recommend that the Companies switch to the vendor's recommended setting "Schedule Storage Based on" to "Load" instead of "Market Price" to ensure that battery storage resources will be able to contribute during periods of high load.

The second setting is related to the "capmin" in SERVM, which sets the minimum operating level of the unit. If a value is not specified, then the model will default to the "capmax" for that unit. For the battery storage resources, the Companies did not set a value for the "capmin", so the maximum capacity therefore also becomes the minimum capacity. This has implications for the level at which battery storage resources can be discharged. For example, if the "capmax" is 100 MW, and no "capmin" is set then the "capmin" will become 100 MW. This means that the unit will not be able to dispatch at levels lower than 100 MW which narrows the hours in which the battery could feasibly discharge. In order to reflect the ability for the battery to dispatch at all levels, we recommend that the Companies model the "capmin" at 0 MW.

III. NGCC COST ESTIMATES ARE AT AN EARLY STAGE AND ARE LIKELY UNDERSTATED

Q. At what stage of development are the Companies' proposed natural gas combined cycle ("NGCC") power plants?

A. The proposed NGCCs are at an early stage of development with important steps in developing the full scope of the projects currently underway or yet to conclude, including the steps necessary to select and negotiate a contract with an engineer, procure, and construct ("EPC") firm.

Q. What is the role of an EPC firm?

A. An EPC firm holds the responsibility for managing the engineering and design of a project, managing its construction, and procuring equipment and commodities needed to construct a project. Typically, electric utilities will work with an EPC firm to build power plants because they lack recent, internal experience in performing these tasks. The owner retains responsibility for overseeing the work of the EPC firm, but the EPC firm ensures that the plant meets commercial milestones and achieves commercial operation.

Q. What would be the benefit of securing an EPC firm at this stage of the process?

A. The Companies contend that they cannot select an EPC firm before they have secured approval of the CPCN.[9] In my experience, while the EPC agreement may not have been fully negotiated and executed, it is entirely reasonable for the winning firm to have been identified and an estimated capital cost to have been developed, based, at least in part, on the winning firm's bid. Importantly, the Companies do *not* have this information and are not even in receipt of bids for EPC services for these plants.

Q. What are the Companies' plans for issuing their EPC RFP?

A. The Companies appear to have changed their contracting strategy during the pendency of this case. In response to JI 1.9(a) the Companies stated:

> *As with all major generation projects implemented over the last few decades, approval of the CPCN is required prior to executing the EPC Agreement. The Companies will be issuing to the market the [original equipment manufacturer] OEM and EPC agreement for bids during the CPCN proceedings to allow execution of the agreement soon after obtaining regulatory approval to implement the projects.*

The Companies now say that they initially[10]

> *assumed a multi-step bid process wherein the first step identified a chosen OEM technology and the second identified a chosen EPC to install that technology. The OEM lead bid strategy requires only a one*

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[9] LGE & KU Response to JI Initial Q9.

[10] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint Intervenors' Fourth Set of Data Requests, Question 4.26(e) (July 7, 2023) ("LGE & KU Response to JI Fourth Data Request Q").

> *step bid process. This change pushed the RFP issuance back for the Mill Creek NGCC. The Brown NGCC is accelerated to the Mill Creek NGCC to minimize duplication of effort and associated cost inefficiencies.*

According to the current project schedules,[11] the EPC RFP was issued on April 25, 2023, and the Companies have stated in discovery that responses to the EPC RFP are due August 28, 2023[12] – the Monday after the hearing in this case concludes. The Companies' project schedule shows that the EPC agreement would not be executed until February 2024.[13]

[11] *See* Attachments 1 and 2, LGE & KU Response to JI Fourth Data Request Q24.
[12] LGE & KU Response to JI Fourth Data Request Q4.26(c).
[13] *See* Attachments 1 and 2, LGE & KU Response to JI Fourth Data Request Q24.

Q. Would it have been feasible for the Companies to not just have advanced the EPC RFP release date but also advanced the schedule for receipt of EPC bids such that the winning bids could be made part of the evidence in this case?

A. While the Companies moved up the EPC release date to end of April 2023, it also extended the length of the bid period from 97 or 98 to 124 days, so it may have been possible. Either way, it certainly would not make sense for the Companies to have a fully executed contract and to have issued a Full Notice to Proceed ("FNTP") to the EPC before receiving Commission approval – that is not at all what I am suggesting. Instead, it is not unusual to have identified the winning EPC firm before Commission approval is sought and even to have issued a limited notice to proceed ("LNTP"). These activities should not commit the Companies or ratepayers to the full or even a majority of the cost of the project. Identifying the specific EPC firm has the benefit of providing much more clarity with respect to the project cost. That is particularly important given the high inflationary environment in which the industry currently operates.

I know of no reason that the Companies could not have delayed the filing of this application to facilitate the inclusion of this information in their application, if that were necessary.

Q. Why do you think the winning NGCC EPC bid would provide useful information for the Commission?

A. I am concerned that the Companies have materially underestimated the cost of the Mill Creek and Brown NGCCs for several reasons.

1. While the Companies received multiple solar and storage bids in response to their generation RFP, the Companies were the only respondents who

offered any thermal generation. With respect to the RFP there are, therefore, no additional, current price data points for the Companies to benchmark or consider for this technology.

2. In addition, while the Companies were able to utilize a PPA index for wind and solar costs – the LevelTen PPA Index14 – to compare to the costs of the winning bids, there is nothing similar for combined cycle plants.

3. Producer Price Indices for inputs into the NGCCs have increased at rates faster than inflation and yet the Companies' current cost estimate seems to be lower than prior estimates produced by their owners' engineer, HDR, and escalated at the rate of inflation.

4. Coal-fired power plants planned for the mid to late 2000s experienced cost increases of 30 – 50% and sometimes more due to escalation in the same commodities that are experiencing significant price escalation today. While they are different technologies, there is still significant price risk for the Companies' NGCC units.

Q. Can you elaborate on your concern with respect to the fact that the Companies were the only respondents providing thermal bids responsive to their generation RFP?

A. While it is not atypical for all-source RFPs to receive thermal plant bids only from affiliates, this means that there are no other bids that can help ground truth potential project costs. We are in a decidedly different economic environment with more volatility

[14] Level Ten PPA Price Index, https://www.leveltenenergy.com/ppa (last accessed July 14, 2023).

that we were in two years ago and that makes cost estimation for major projects particularly challenging.

Q. The basis for the cost estimate of the NGCCs is a feasibility study conducted by HDR. Does that not alleviate concern about the validity of the cost estimates?

A. I am concerned that the HDR study[15] is not a robust source for the capital costs of these NGCC units. First, the contract between HDR and the Companies shows that HDR was authorized to spend only $83,500 on the study, but the deliverables and services provided were numerous and include:[16]

- *Develop comparative cost estimates and site arrangements for 2 E.W. Brown sites (Webb Farm & U1-2). This item shall be performed in the first 45 days.*
- *Refresh and refine the Work performed under PO# 1070477 as described below*
- *Develop Large Generator Interconnection request technical package for submittal to TranServ. The data technical includes impedance and time constants data as well as required models and curves. A conceptual one-line diagram will also be provided for each site representing site specific transmission interconnection voltage. This item to performed in the first 60 days.*
- *Assess generation scenarios 1x1 (GE 7HA.03, Siemens 8000H and MHPS 501JAC all having a summer rating in excess of 600 MW) and 2 F class simple cycle combustion turbines*
- *Provide assessment of single shaft vs. multi-shaft configurations*
- *Provide assessment of impact of dual fuel combustion system regarding natural gas operation (performance, emissions and life cycle cost)*
- *Plant Performance and Heat Balances*

[15] Confidential Attachment to LGE & KU Response to JI Initial Q9(e).
[16] Attachment to LGE & KU Response to JI Initial Q26(b).

- *Plant Emission Profiles*
- *Site Arrangements*
- *Water Balances with site specific assessment of intake/discharge*
- *One Line Diagrams*
- *Fuel Pressure Requirements*
- *Contracting strategy to evaluate the Owner Furnished Equipment (OFE) approach from a project execution and risk perspective.*
- *Project Schedules*
- *Top down cost estimates with spare and service agreement costs*
- *Cost estimate options to include; fuel oil backup storage/combustion facilities for identified configurations, SCR (if required for NSPS for site under netting analysis) and gas compression if required to meet CTG OEM gas pressure requirements*
- *Plant proforma for each technology and configuration*
- *Infrastructure assessments for application of the three configurations at the existing E.W. Brown, Mill Creek and Green River sites including Buyer capital costs for site specific interconnection, pipeline and water supply/discharge*
- *Meetings*
    - *Kick off meeting conducted via conference call*
    - *Weekly coordination conference calls*
    - *Optional site meeting(s) attended by the Engineer's Project Manager to confirm study criteria and collect applicable field data to be determined on an as-needed basis.*

Engineer shall provide the following deliverables in support of this project:

- *Large Generator Interconnection request technical packages for submittal to TranServ. The technical data includes impedance and time constants data as well as required models and curves. A conceptual one line diagram shall also be provided for each site for one NGCC* *and one Simple Cycle configuration. (Within 60 days of starting Work)*

- *Feasibility Report defining the site design conditions, emissions profiles, thermal performance, contracting strategy, infrastructure requirements, capital cost, O&M cost and project schedule with appendices to include the following:*
    - *Appendix A Site Arrangements (E. W. Brown two unit NGCC, E.W. Brown single unit NGCC, E. W. Brown Simple Cycle, Mill Creek two unit NGCC, Mill Creek single unit NGCC, Mill Creek Simple Cycle)*
    - *Appendix B Heat Balance Diagrams (GE 7HA.03, Siemens 8000H, MHPS 501JAC, Simple Cycle)*
    - *Appendix C Water Balances (E. W. Brown two unit NGCC, E. W. Brown single unit NGCC, E.W. Brown Simple Cycle, Mill Creek two unit NGCC, Mill Creek single unit NGCC and Mill Creek Simple Cycle)*
    - *Appendix D Single Line Diagrams (E. W. Brown two unit NGCC, E. W. Brown single unit NGCC, E. W. Brown Simple Cycle, Mill Creek two unit NGCC, Mill Creek single unit NGCC and Mill Creek Simple Cycle)*
    - *Appendix E Project Schedule (E. W. Brown two unit NGCC, E. W. Brown single unit NGCC, E.W. Brown Simple Cycle, Mill Creek single unit NGCC, Mill Creek two unit NGCC and Mill Creek Simple Cycle)*
    - *Appendix F Project Cost Estimates (E. W. Brown two unit NGCC, E. W. Brown single unit NGCC, E. W. Brown Simple Cycle Mill Creek single unit NGCC Mill Creek two unit NGCC and Mill Creek Simple Cycle)*
    - *Appendix G Life Cycle Cost Analysis (E. W. Brown two unit NGCC, E. W. Brown single unit NGCC, E. W. Brown Simple Cycle Mill Creek two unit NGCC Mill Creek one unit NGCC and Mill Creek Simple Cycle)*[17]

Notably the scope says that HDR shall "refresh and refine the Work performed under PO# 1070477" – so using prior work appears to be at least part of the way that this broad

[17] *Id.*, Scope of Work at 2–3.

scope was managed on a limited budget. It is not clear what PO# 1070477 refers to, but HDR was also the Companies' Owner's Engineer ("OE") that performed the 2013 feasibility study for the NGCC that would have been located at the E.W. Brown site, so that study may have helped inform this work.

Both the 2013 and 2022 feasibility studies include multiple NGCC configurations. The Companies plan to install J or H class turbines[18] and the configurations including those turbines are smaller in size in the 2013 study than in the 2022 study. Nevertheless, whether in comparison to the small J/H configurations or the larger F class configurations, the costs in the 2013 study are higher than the costs of the NGCC configurations in the 2022 study as shown in Figure 3.

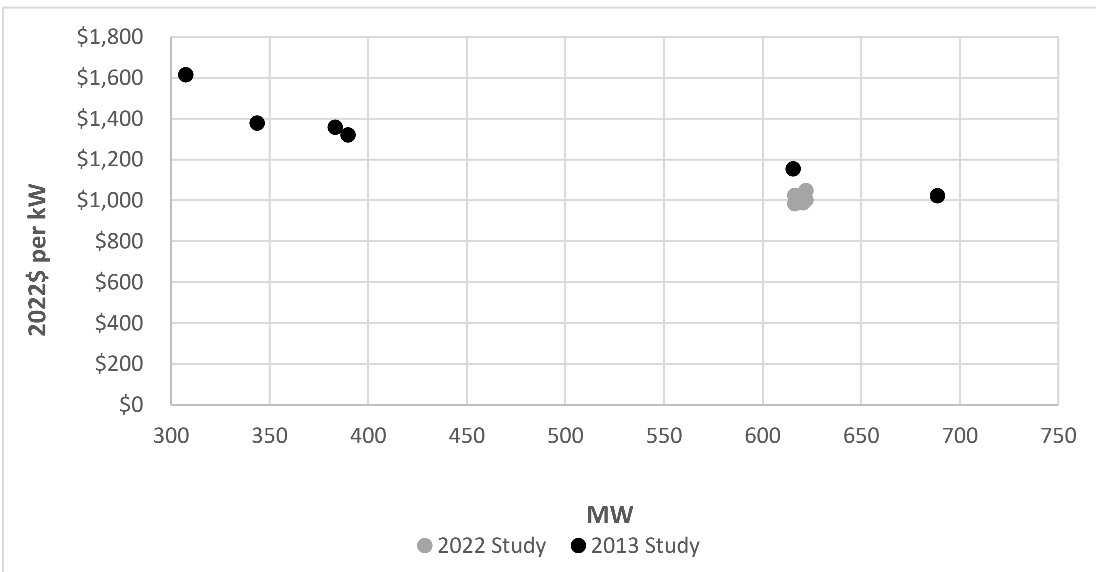


Figure 3. NGCC Cost per kW Comparison between 2013 and 2022 HDR Feasibility Study[19]

[18] Direct Testimony of Lonnie E. Bellar, In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan, Case No. 2022-00402, at 1 (Dec. 15, 2022) ("Bellar Direct").
[19] Attachment to LGE & KU Response to JI Initial Q9(e) and Attachment to Response to Sierra Club-1 Question No. 1.9 in Case No. 2014-00002.

It was not possible to adjust these costs so that they capture the same construction financing assumptions, pipeline and interconnection costs, turbine classes, or are divided by the same capacity measure, e.g. summer rating, or are adjusted for differences in regional labor costs, etc. so the figure should be taken as a rough comparison.

A similar dynamic is shown when comparing the HDR estimates for this case to prior HDR studies in Michigan (2017) and Oregon (2018).

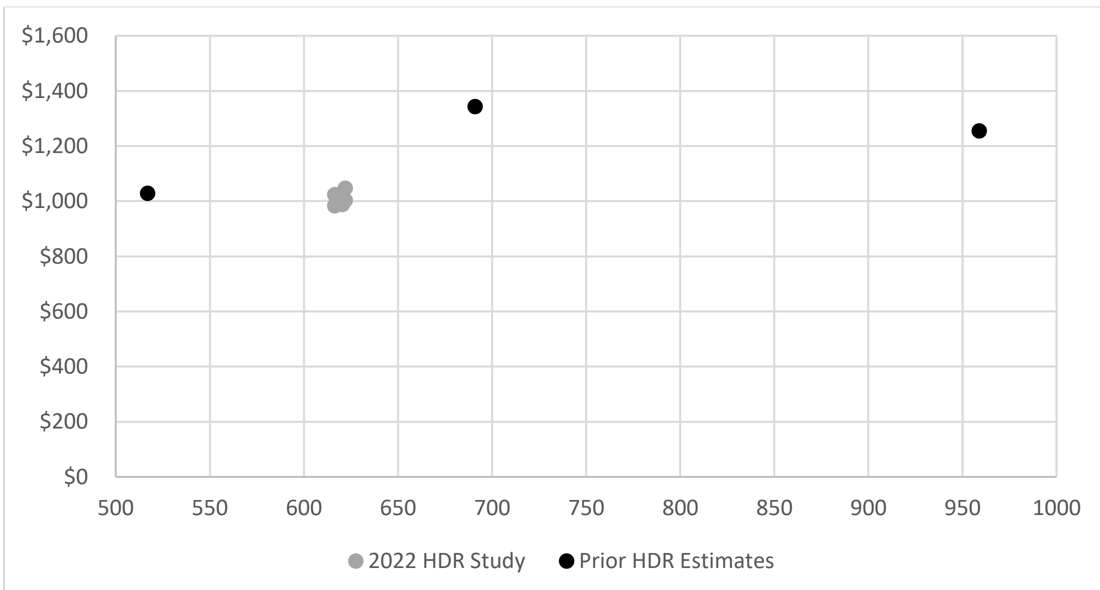


Figure 4. Comparison of 2022 HDR Feasibility Study to Prior NGCC Cost Estimates[20]

The costs are again similar or even higher than those given in the current HDR study.

[20] *See* Attachment to LGE & KU Response to JI Initial Q9(e); *see also* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UYgFAAW; https://assets.ctfassets.net/416ywc1laqmd/3zjZWYwpKoG1vkuAlMG9ew/9c7eaf8107b8f4644b7ce51dafd3e0c2/sso-thermal-pumped-hydro-hdr-2018.pdf.

Q. Would you expect costs to be similar or even to have gone down in real terms for an NGCC?

A. No, while there are some cost improvements to be expected from the advent of larger simple cycle turbines, inflationary impacts have been felt broadly through our economy and some of the key inputs into the NGCCs have experienced increases in excess of inflation as shown in Figure 5.

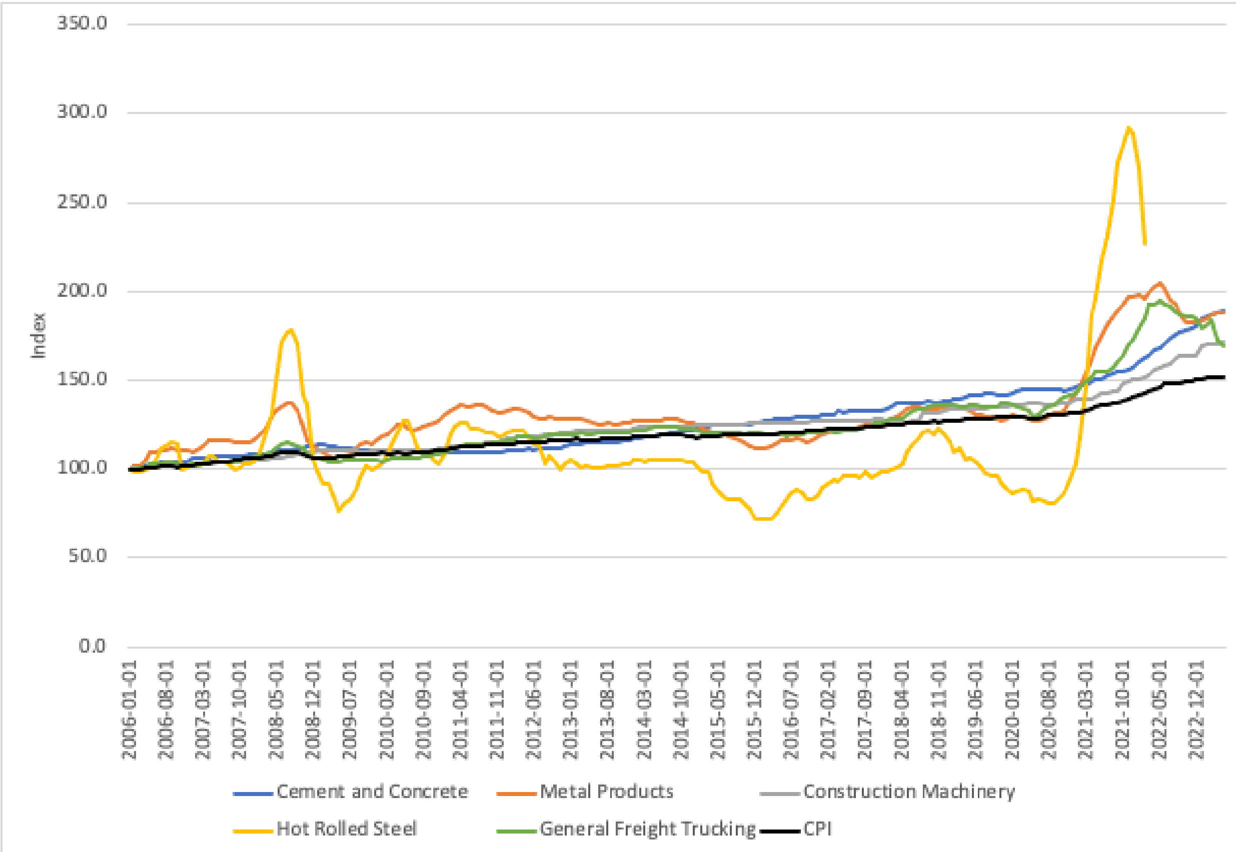


Figure 5. Index Measures of Selected NGCC Inputs Compared to CPI

Each of these indices for Cement and Concrete, Metal Products, Construction Machinery, Hot Rolled Steel, and General Freight Trucking have, for the last eight quarters or more, increased at rates that exceed the Consumer Price Index ("CPI"), a measure of inflation.

Q. Have you seen commodity price increases and other escalation adversely affect thermal plant capital cost in the past?

A. Yes, in the mid to late aughts, when many utilities were contemplating building new coal plants, escalation in commodities caused price increases at many proposed projects of 30 – 50% and sometimes even more. Clearly a steam turbine intended to burn coal has some significant differences from a combined cycle project including a difference in commodity quantities, but those differences would not shield the Companies' NGCCs from all cost increases.

From a broader perspective, coal plants are tailored to specific coal types and seams, while combined cycles burn a more standard pipeline gas. While the tailoring for coal units introduces more variability in the OEM equipment from the steam generator and air quality control suppliers, the commodity costs tended to affect the balance of plant construction significantly. Both coal and natural gas plants require significant amounts of structural steel, wiring, piping, cement, grating, etc. This balance of plant material pricing is generally estimated off of index pricing and if fixed, does not become so until the final contract is signed. The balance of plant can be a significant portion of construction costs, anywhere from 40-60%.

While there are material differences between coal and gas plants, the recent escalation shown in these key commodities generally exceeds that which occurred during the mid to late aughts as show in Figure 6.

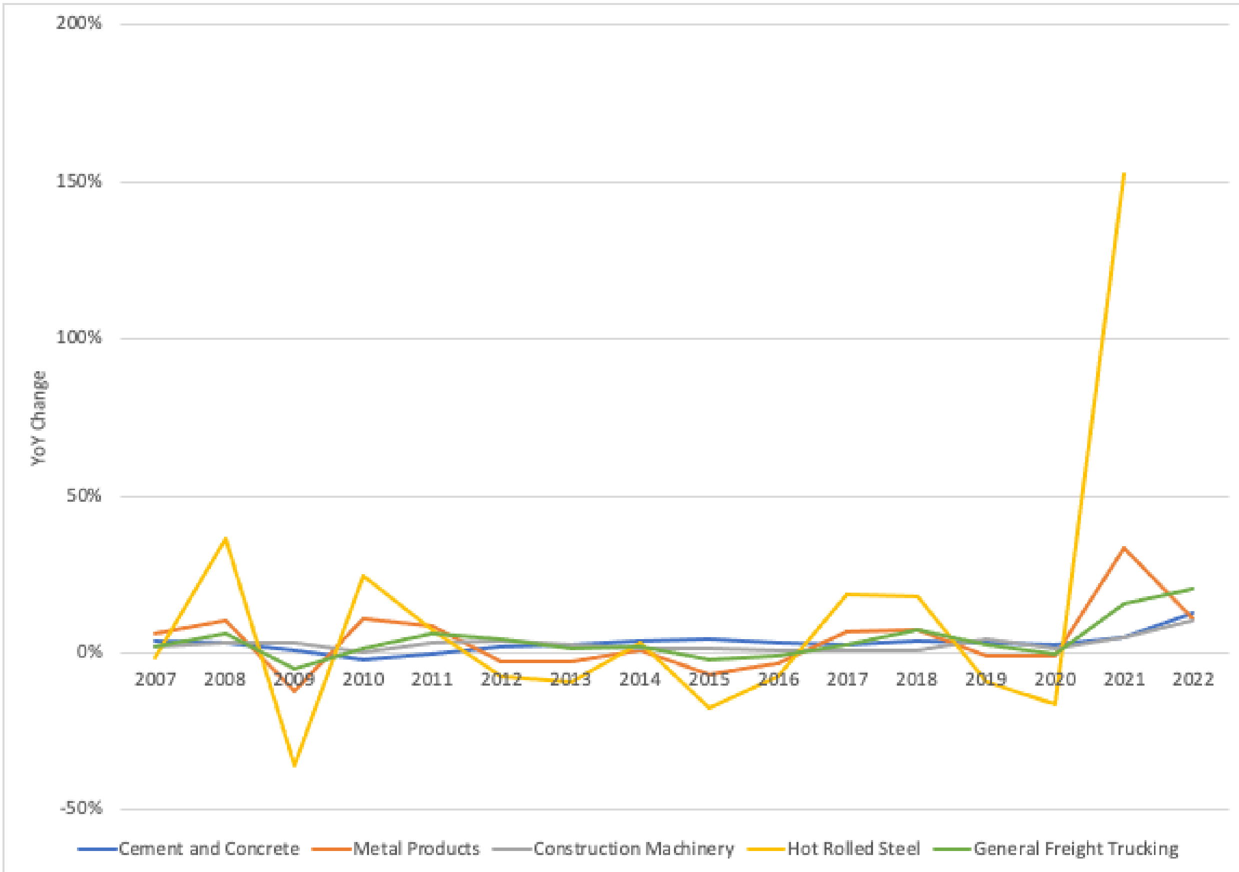


Figure 6. Year on Year Change in Selected PPIs

Notably, the increases in commodity costs in the mid aughts were driven in part by demand for these goods and services not just in new power plants, but also environmental control retrofit projects. The Companies have planned these projects for in-service dates at a time when there will be demand for similar goods and services in order to bring other power plants into compliance with the Good Neighbor Plan or to replace those power plants.

Q. Do the Companies acknowledge some uncertainty in their cost estimate?

A. Yes. The Companies have said that HDR characterizes the current cost estimate as being at an Association for the Advancement of Cost Engineering ("AACE") Class 3 with an error band of -5-15% to +10-30%. The high side of this error band serves as the cost sensitivity used in the modeling our team conducted for this case and discussed in my testimony below.

IV. MODELING CONDUCTED

Q. Turning to the modeling you conducted, can you describe the modeling process that you used?

A. After making some changes to the model inputs and settings, we used an iterative process of testing portfolios in SERVM and in PLEXOS to determine how resources contributed to reliability and to total system cost.

Q. In your iterative process, what standard did you use to evaluate portfolio reliability?

A. We evaluated portfolio reliability based on loss of load expectation ("LOLE"), and we sought to develop portfolios that resulted in a LOLE score of less than 1.0. The Companies' have said that they "treat an LOLE of 3.57 as consistent with maintaining adequate reliability because this LOLE is aligned with the Companies' minimum reserve margin targets, i.e., any portfolio with a lower LOLE than 3.57 provides more than adequate reliability."[21] In general, we are supportive of the thrust of the Companies' reserve margin analysis, which is intended to evaluate the tradeoff between reliability and economics, but the Companies did not ultimately propose a portfolio with an LOLE value that exceeds 1.0, a typical reliability planning target, and falls below 3.57. We, therefore, eliminated portfolios that exceeded a 1.0 LOLE.

[21] Exhibit SB4-1, page 13.

Q. Why did you not rely solely on the Companies' reserve margin targets to determine optimal portfolios?

A. As the Companies' noted in their SB4 application, "All of the portfolios consisted of the Companies' existing resources without the seven units the Companies assume or propose to retire but with the proposed Mill Creek NGCC (which had 10.3% summer and 17.6% winter reserve margins). Each portfolio then added 480 MW of SCCT capacity, 4-hour BESS capacity, 8-hour BESS capacity, or dispatchable DSM. Therefore, the portfolios all had identical reserve margins, but they had markedly different LOLE values, and therefore reliability, ranging from 3.57 (the SCCT portfolio) to 15.14 (the dispatchable DSM portfolio)."[22] This is the challenge with reserve margin targets, they only deliver the desired level of reliability for the portfolio upon which they were developed. They quickly lose their meaning when examining different portfolio compositions. This is the reason that, if possible, we have a preference for directly evaluating portfolio reliability rather than using a proxy value such as a reserve margin target.

Q. What changes did you make to the Companies' modeling settings and inputs?

A. In addition to the setting changes described above, we also made the changes described in Table 2.

[22] Exhibit SB4-1, page 13.

Table 2. Summary of Changes Made to PLEXOS Database

Modeling Input or Setting	LG&E/KU	EFG
Mercer County Solar Project*	Not Modeled	Modeled
Marion County Solar Project*	Not Modeled	Modeled
Brown BESS*	Not Modeled	Modeled
Mill Creek 2 Conversion to Gas*	Not Modeled	Modeled
Additional DSM*	Not Modeled	Modeled
Chronology	Partial (load duration curves)	Fitted (chronological)
Curve Fitting Period	Month	Day
Count of Blocks	24	5
Rolling Horizon	No	Yes
Step Size	N/A	6

*These resources were not included in all portfolios.

The Mercer County Solar, Marion County Solar, and Brown BESS projects were not in the PLEXOS database used by the Companies to develop their initial portfolios, so we needed to add them. While the Companies developed a feasibility study that looked at the cost of converting certain Mill Creek and Brown coal units to gas utilizing their existing steam turbines, those options were not explicitly included in the Companies' modeling for this application.

The additional energy efficiency and demand response (DSM) included is supported by Mr. Grevatt's analysis and testimony.

The rationale for the setting changes is as described in my testimony above.

The data used to set up the Mercer County solar, Marion County solar, Brown BESS, and Mill Creek 2 conversion costs are given in Table 3.

Table 3. Data Sources Used to Develop PLEXOS Resource Additions

Resources	Source
Mercer County Solar	LG&E/KU PROSYM files; PLEXOS solar shapes
Marion County Solar	LG&E/KU PROSYM files; PLEXOS solar shapes
Brown BESS	Workpaper "CONFIDENTIAL_20221209_ResourceScreeningModel_0308"
Mill Creek 2 Conversion	Attachments to JI 1-1

The changes made to the Companies' SERVM database are given in Table 4.

Table 4. Summary of Changes Made to SERVM Database

Modeling Input or Setting	LG&E/KU	EFG
Load Shapes	Includes error identified in JI 2-60	Corrected load shapes as per those given in JI 2-60(c)
Battery Settings: "Schedule Storage Based On"	Market Price	Load
Battery Settings: "Capmin"	No value specified – SERVM defaults to "capmax"	0 MW
Solar Shapes	All solar based on existing 10 MW Brown solar facility	Used weather varying shapes generated by Astrapé
Additional energy efficiency ("EE") and demand response ("DR")*	Not modeled	Additions: 65 MW of EE 35 MW of summer DR 17 MW of winter DR
Case 8 renewable and storage projects*	Not all renewable and storage RFP projects were set up in SERVM	Included each renewable and storage RFP project from the Companies' Case 8 portfolio
Mill Creek 2 Conversion*	Not evaluated by the Companies	Mill Creek 2 converted to natural gas

*These resources were not included in all portfolios.

Q. What portfolios did you ultimately develop?

A. We developed two portfolios – one is substantially based on the Companies' all renewable and battery storage portfolio, Case 8, but adds the conversion of Mill Creek 2 to gas and the second includes only the Mill Creek NGCC plus renewables and battery storage. Both portfolios include the additional energy efficiency and DR developed by Mr. Grevatt. The capacity additions in each portfolio are given in [redacted]

[redacted]

Q. What are the costs of each portfolio?

A. The net present value of revenue requirements of each portfolio is given in Table 5.

Table 5. PVRRs of Portfolios Modeled Compared to the Companies' Preferred Plan

Portfolio	**Difference from Companies Preferred Plan**
Renewables Plus MC2 Conversion	$1,399,273,493~~213,460,907~~
Renewables Plus One NGCC	$290,378,525~~104,565,939~~

Q. Are there particular risks that might change the relative cost outcomes of these plans?

A. Yes. There are four primary risks, one of which is quantifiable and the other three are not, at least with the data available currently. First, the natural gas prices used by the Companies are generally higher in real terms than the valleys in historical prices as shown in [redacted] but also miss the peaks in monthly prices and do not capture the sometimes daily volatility that can occur in gas pricing such as during winter storm events. It was not possible, even with the High Case gas price to test the impact of that volatility on customer cost because it still consists of a relatively smooth, just elevated price curve.

[redacted]

Second, several of the solar projects in these portfolios may be eligible to receive the production tax credit (“PTC”) rather than the investment tax credit (“ITC”). It is not clear how each treated the tax incentives or whether the power purchase agreements would permit any change in the tax credit taken to accrue to the Companies, but if it were possible, there is a significant potential cost reduction as shown in Figure 70.

[23] Based on EIA data and the SAW Workpapers for the PLEXOS model.

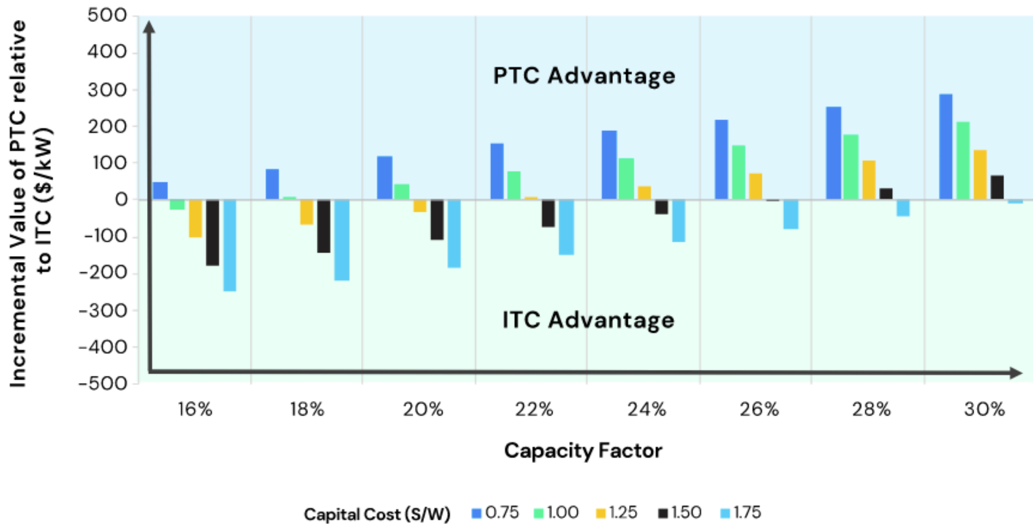


Figure 70. Relative Value of PTC to ITC for Solar Projects[24]

A change of $4 per MWh in the cost of the 1,200 MW of solar PPAs in the Renewables plus Mill Creek 2 conversion portfolio would provide a PVRR reduction benefit of over $100 million.

Third, as discussed above, there is significant risk that the costs of the combined cycle units will go up and materially so. Because the conversion of Mill Creek 2 to gas would include some of the commodities at risk for the NGCCs, the cost of that conversion was also escalated by 30% and the resulting differences in PVRR are given in Table 6.

Table 6. PVRRs of Portfolios Modeled Compared to the Companies' Preferred Plan with Capital Cost Sensitivity

Portfolio	**Difference from Companies Preferred Plan**
Renewables Plus MC2 Conversion	$993,180,524~~807,367,938~~
Renewables Plus One NGCC	$81,887,968~~(103,92x4,618)~~

[24] L. Batra, et al., ICF Int'l, *Solar economics: The PTC vs. ITC decision*, https://www.icf.com/insights/energy/solar-economics-ptc-vs-itc.

Fourth, as discussed more below, there is also a significant regulatory risk with respect to the ability of these NGCCs to comply with the EPA's recently proposed new GHG rules for new and existing coal and natural gas-fired power plants.

Q. How do the CO_2 emissions of these portfolios compare?

A. The CO_2 emissions for each portfolio are given in Figure 11.

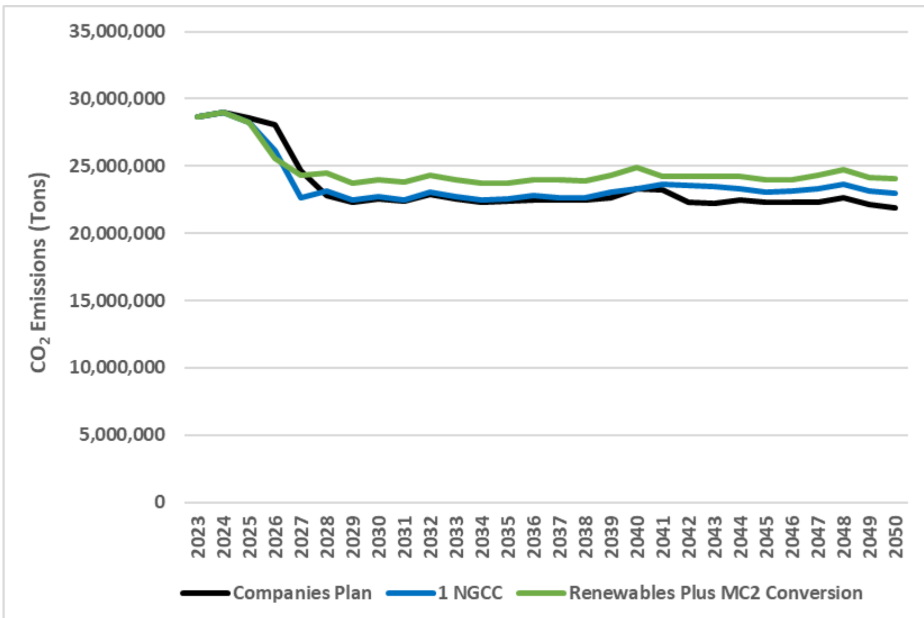
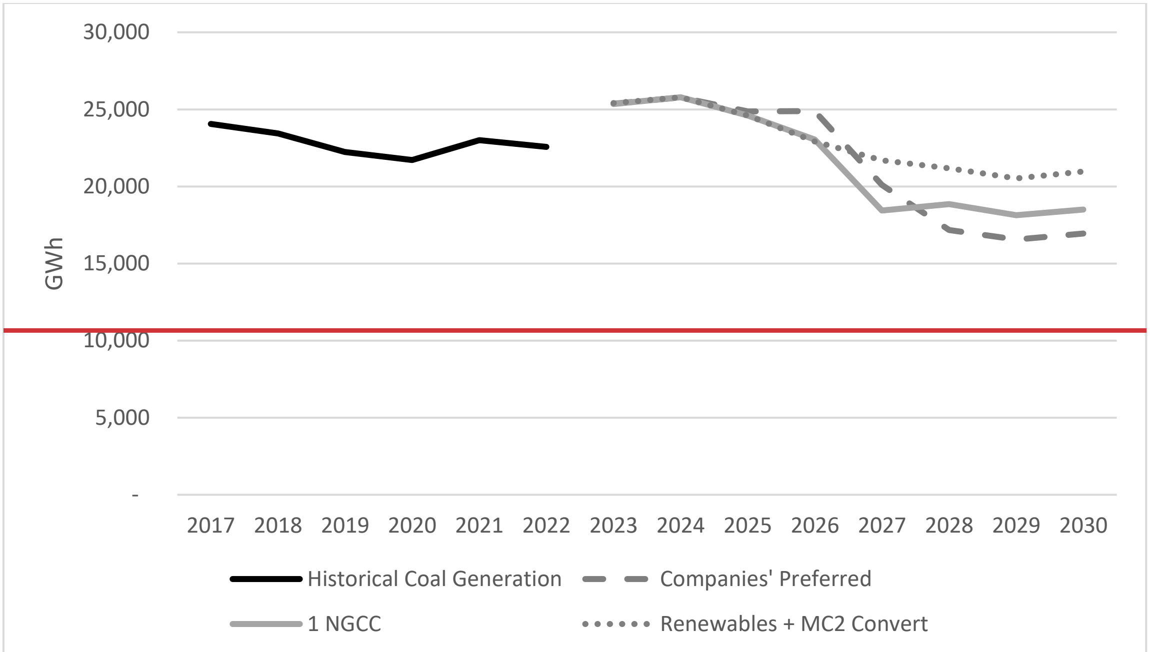


Figure 11. Annual CO_2 Emissions by Portfolio

Q. How likely do you think the Companies' CO_2 emissions are to be well predicted by any of these portfolios?

A. I do not think the Companies' modeling gives a robust prediction of their CO_2 emissions even in the near term. First, PLEXOS over-dispatches the Companies' existing coal units even in the first year of the planning period before any resource changes have happened as shown in Figure 12. Starting in 2023, the first year of the simulation, the Companies' PLEXOS model dispatched the coal units enough to produce about 2,800 GWh more energy than they actually generated in 2022 – an increase of about 4~~12~~%. ~~and noticeably~~

~~higher than any of the past seven years.~~



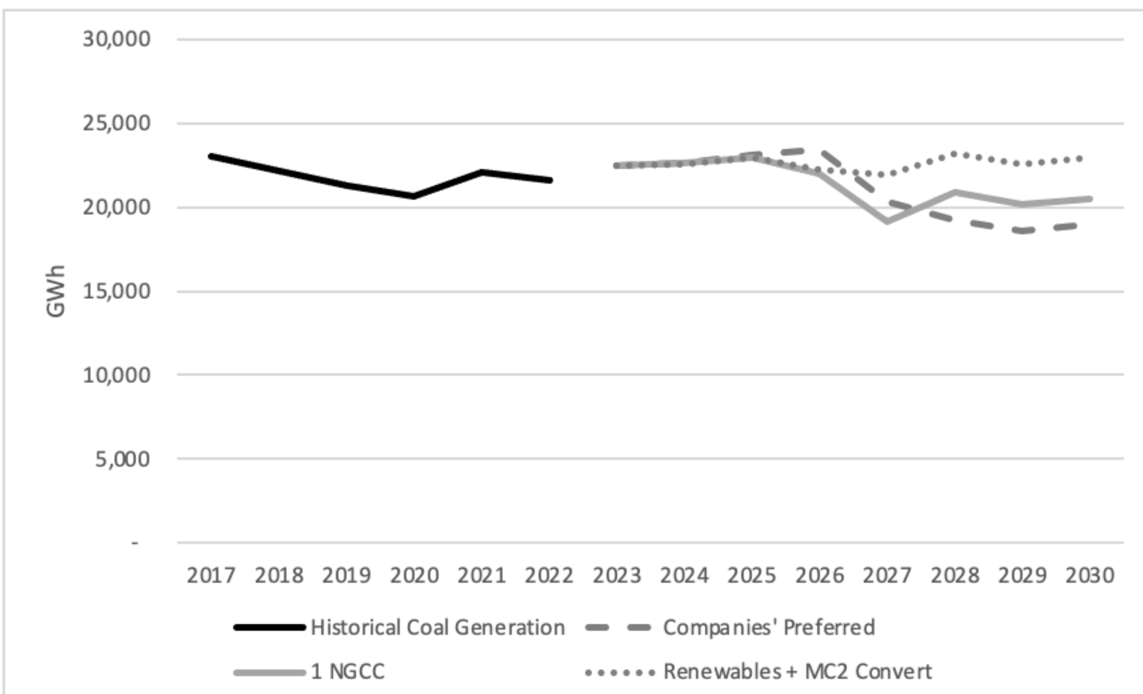


Figure 12. Comparison of Historical vs. Modeled Coal Generation

I suspect a primary reason for this is that the Companies' PLEXOS topology is set up as if the Companies were an island with no ability to buy or sell power from its neighbors. In reality, there is interchange of power with neighboring utilities every day on the Companies' system.

In the post 2034 timeframe, the CO_2 emissions would be particularly misleading because while the Companies' current plan is to retire its remaining units, excluding Trimble County Unit 2, they modeled all these units as operating through the end of the planning horizon (i.e., 2050). The current retirement schedule is given in Table 7.

Table 7. Retirement Schedule of Companies' Coal Units[25]

Unit	**Retirement Year**
Ghent Unit 1	2034
Ghent Unit 3	2037
Ghent Unit 4	2037
Mill Creek Unit 3	2039
Mill Creek Unit 4	2039
Trimble County Unit 1	2045

The Companies' modeling also does not contemplate any requirement to reduce CO_2 emissions at individual units or across its system. I do not think that is a realistic expectation and therefore I would not expect the projected CO_2 emissions from PLEXOS to be realistic.

Q. What are the reliability metrics for each portfolio?

A. The LOLE and EUE for each portfolio is given in Table 8. The LOLE of the Companies' Preferred Plan differs from that given in the Companies' SB 4 application because we reran the plan including the solar shapes developed for us by Astrapé.

[25] Bellar Direct at 5.

Table 8. Portfolio Bulk Level Reliability Statistics

Portfolio	**Loss of Load Expectation (LOLE)**	**Expected Unserved Energy (MWh)**	**EUE as % of Average Energy Requirements**
Companies' Preferred Plan	0.24	10	0.00003%
Renewables Plus MC2 Conversion	0.63	68	0.00020%
Renewables Plus One NGCC	0.91	60	0.00018%

V. PLANNING IN AN UNCERTAIN AND CHANGING WORLD

Q. What planning related risks do you see as major challenges for the Companies?

A. The electric power industry is confronted with numerous challenges—including inflationary impacts, changing patterns of demand, and new patterns of extreme weather events—while needing to simultaneously manage a rapid transition away from carbon-emitting generation. Some of these challenges the industry has encountered before such as inflation and anticipated increases in demand in the 1970s and 1980s. But the severity of heat waves and large storms will likely become more frequent due to climate change[26] and predicting the specifics of its impacts is very challenging.

The risks due to climate change are both economic and physical. On the economic side, any utility relying on fossil-fired generation risks stranding capital investments in that infrastructure or incurring costs to offset or reduce carbon emissions from those plants. Notably, the Companies' parent corporation has a commitment to net zero emissions by 2050.[27] Most recently, that risk has manifested in the EPA's proposed rule addressing carbon emissions at fossil-fuel fired power plants. That rule is discussed more below. Political action to address climate change through mechanisms that would cause these costs to be incurred is buoyed by the majority of Americans who support businesses, corporations, and the federal government doing more to address climate change.[28]

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[26] U.S. Envtl. Prot. Agency, Climate Change Indicators: Weather and Climate, https://www.epa.gov/climate-indicators/weather-climate.

[27] PPL, *Energy Forward: PPL's 2021 Climate Assessment Report* (2022), https://www.pplweb.com/wp-content/uploads/2022/01/PPL_Corp-2021-Climate-Assessment_2022-01-04.pdf.

[28] Alec Tyson et al., *What the data says about Americans' views of climate change*, Pew Research Center (Apr. 18, 2023), https://www.pewresearch.org/short-reads/2023/04/18/for-earth-day-key-facts-about-americans-views-of-climate-change-and-renewable-energy/.

On the physical side, climate change has a variety of infrastructure impacts that we are just starting to see and understand. Those potential impacts include:[29]

1. Increased demand for electricity;
2. Reduced thermal generating capability;
3. Reduced cooling water availability;
4. Reduced solar generating capability;
5. Reduced capacity on transmission and distribution lines and increased risk of outage on those lines; among others.

This is not intended to be an exhaustive list but rather a cataloging of those risks that the electric industry generally understands and does not typically quantify or explicitly plan for. Two of the challenges in planning for these risks are the lack of information to quantify their impacts and the siloing of planning activities between the generation, transmission, and distribution systems. These challenges demand creativity; a widening of actors involved in planning, e.g., experts in consumer behavior and experts in climate change and meteorology; and a quickening of the pace at which we might otherwise like to try new systems and ways of thinking. I often see the word "balanced" used in discussing energy transition, but that "balance" rarely takes into account the physical changes that are coming and our inability to anticipate their speed and magnitude. Though electric system planning is a forward-looking exercise, much of it is typically based on backward looking information. Regression models for load are based on

[29] *READi Insights: Extreme Heat Events and Impacts to the Electric System*, EPRI (Sept. 2022), https://www.epri.com/research/products/000000003002025522.

historical sales. Volatility in fuel prices is based on historically experienced volatility. Load in reliability models is based on loads and temperatures observed during a historical period. Yet because we have never experienced global climate change on the scale of that happening today, we have no history to embed into these models. Power system planning is a very data intensive and complicated exercise thus the level of complexity and thought needed to incorporate climate risk into that exercise is demanding and cannot be ignored even though there is uncertainty about how quick and how severe it will be.

Q. How do you see these risks informing this docket and the Companies' future planning exercises?

A. First, neither the Companies' plan nor any of the plans presented in my testimony will go far enough to reduce carbon emissions on the Companies' system. The Companies' plan would [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].[30] I understand that the modeling conducted for this application was not intended to provide a specific resource plan for those out years, but I mention this as an indication of how much there is left to accomplish. Adding new natural gas-fired generation reduces overall system emissions now, but those units will also make the next increment of reduction that much harder to achieve because their emissions will also have to be mitigated or eliminated at some point well before the end of their anticipated technical lives.

The Companies are behind many of their peers in transitioning their electrical system. The most recent Sierra Club report on utility progress towards reducing carbon emissions

[30] Wilson Direct, SAW-2 Confidential Workpapers, CONFIDENTIAL_03_PROSYM, Phase 3.

ranked the Companies amongst the worst performing utilities in the country in taking action to reduce carbon emissions – earning a failing grade.[31] The Companies also have no utility scale wind on their system. Their largest solar project is the 10 MW Brown solar facility which came online in 2016 – no additional utility-scale solar has been built on its system since then though the Companies are attempting to add the Rhudes Creek and Ragland projects. That the Companies would like to build or purchase 1,200 MW of solar is generally a positive and is an important part of putting the Companies on a path to transform their electricity mix. But the Companies need to maintain as much flexibility and optionality as possible to add more zero carbon resources quickly.

I would make three broad categories of recommendations that the Commission direct the Companies to take in anticipation of their next IRP or CPCN application:

1. Transparency – The Companies need to reinvent their planning process to be more clear about how the Companies make decisions and incorporate expertise and knowledge outside the Companies including from its ratepayers.

2. Risk Aversion – The Companies should seek to understand the many risks climate change poses to their system and quantify those risks as much as possible. Those risks should also inform the resources that are contemplated and pursued.

3. Regulatory Updates – The Companies should begin planning for how they might meet the EPA's fossil fuel carbon rules now and provide that plan to the Commission. The Companies should also, if one or more NGCC units is/are approved by this

[31] *See* Cara Bottorff et al, The Dirty Truth About Utility Climate Pledges, Version 2, Sierra Club, Figure 4 (Oct. 2022), https://www.sierraclub.org/sites/www.sierraclub.org/files/2022-09/sierra_club_the_dirty_truth_report_v2_2022_0.pdf.

Commission, provide regular updates on the project schedules, the negotiations with the EPC contractor and other milestones, and the project cost.

On transparency, I give the Companies high marks for their responsiveness to discovery questions and their willingness to clarify those responses that were not clear outside of the formal discovery process. However, the transparency of decision-making is decidedly lacking. From an external perspective, it was an abrupt pivot to go, within one year, from a plan that added several hundred megawatts of CT and solar by 2028 to one that adds over a thousand megawatts each of combined cycle and solar capacity. It is not clear how the Companies got from point A to point B. And it does not appear that those decisions arose from a process that was informed by stakeholders outside the Companies who have both their own expertise and their own local knowledge to provide. These kinds of concerns are one of the reasons we urged the Companies to adopt an IRP stakeholder process in our comments on the 2021 IRP. This would open up a more frequent line of communication between the Companies and stakeholders as well as opportunities for the Companies to be clear about their intentions and decision-making approach before entering into a litigated case.

As it relates to risk aversion, an obvious place to think about incorporating climate change risks is in the Companies' reliability modeling using SERVM. The loads in SERVM are pegged to a historical temperature series and to historical patterns of demand. There are emerging efforts at producing temperature data for uses like reliability modeling that could account for climate change risk[32] and the Companies ought to

[32] *See, e.g.*, EPRI, An Approach to Synthetic Future Climate Hourly Profiles

explore doing the same. The temperature time series used for the Companies' SERVM modeling (see the trend lines in Figure 3) already shows that winter temperatures experienced in Louisville and Lexington are on a sharp upward trend. These graphs are not intended to show exclusively warming induced by global climate change, however, they provide meaningful information given the context of rising temperatures across the entire globe and the relationship between those increases and GHG concentrations.

for Power System Modeling (2022), https://esca.epri.com/pdf/EPRI-2022-Synthetic-Future-Climate-Hourly-Profiles-for-Power-System-Modeling.pdf.

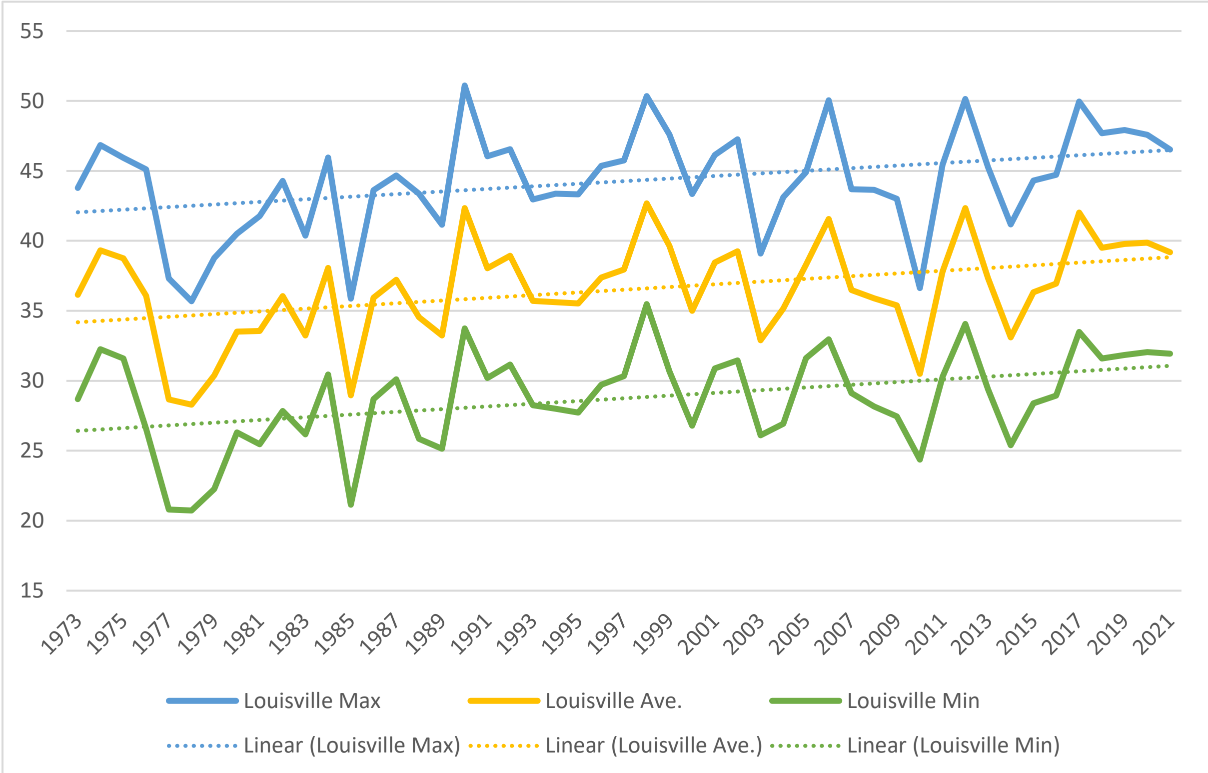

Figure 13. Average of January, February, and December Daily Minimum, Maximum, and Average Louisville Temperatures in Data Used to Create SERVM Loads[33]

[33] Attachment, Response to JI Fourth Data Request Q23, *JI DR4 Q23 Historical Hourly Figures* (“Attach., JI Fourth Data Request Q23”).

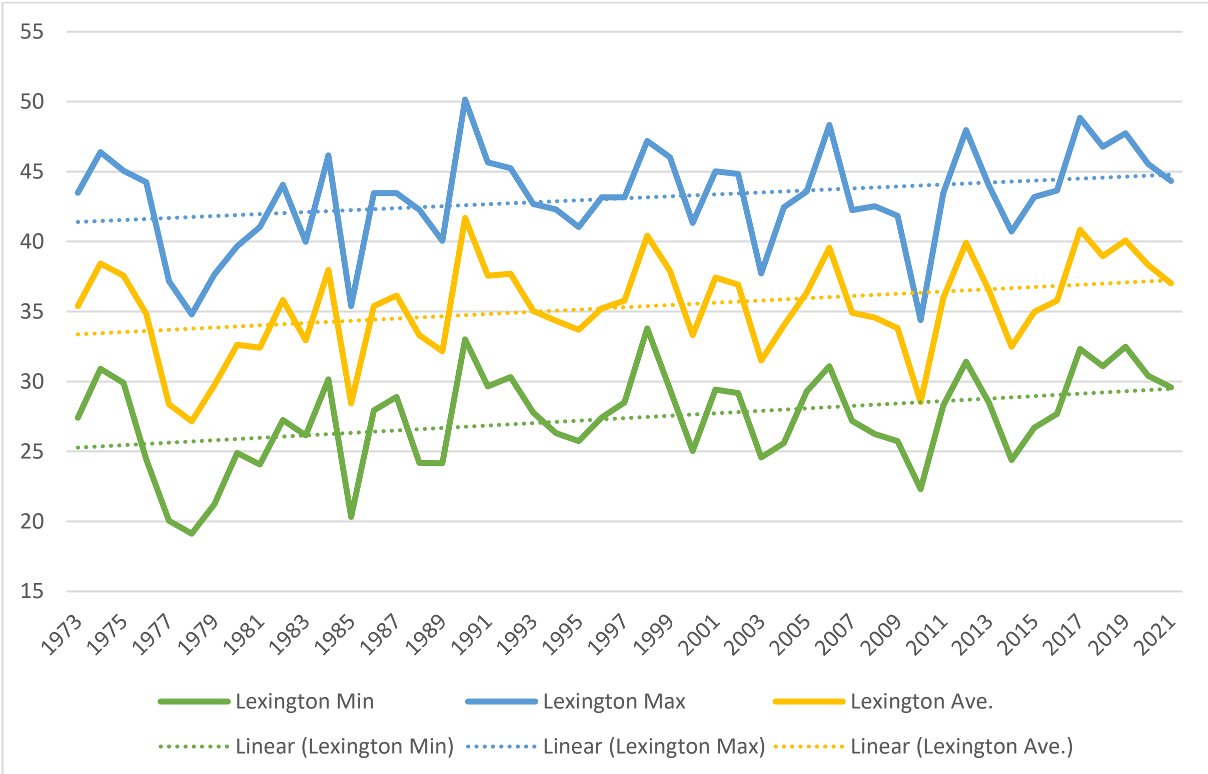

Figure 14. Average of January, February, and December Daily Minimum, Maximum, and Average Lexington Temperatures in Data Used to Create SERVM Loads[34]

The trend lines suggest that average winter temperature would *increase between 8 and 10 degrees* in a century. For context, Louisville's Climate Vulnerability Assessment predicts an increase in average temperature across the year of 5-8 °F and an increase in the extreme minimum temperature of 6-10°F in the period 2049-2060.[35] Summer temperatures in the Companies' data also show an upward trend.

The Companies' planning needs to be much broader to capture the possibilities for carbon emissions reductions. The Companies would need to model technologies to

[34] Id.

[35] Louisville Office of Advanced Planning & Sustainability, *Climate Change Vulnerability in Louisville, Kentucky* (Mar. 2020), at 3, https://climatewise.org/wp-content/uploads/projects/louisville/louisville-vulnerability-assessment-final.pdf.

reduce carbon at the plant site such as firing with hydrogen, capturing and sequestering carbon dioxide, and limiting coal plant capacity factors as well as other technologies it has not yet modeled such as medium and long duration storage, high voltage interconnections to bring renewables, particularly wind, from other states into Kentucky, novel DR such as vehicle to grid programs, and explicitly modeling more energy efficiency and other distributed energy resources ("DERs"). Those resources located on the customer-side of the meter should have their costs and/or energy and peak load impacts adjusted for benefits[36] not typically captured in power system planning.

The Companies also need to evaluate how climate change would impact the infrastructure that serves customers, because that is also at risk. A comprehensive climate risk assessment would help direct planning efforts and determine which physical assets are most at risk.[37]

With regards to regulatory updates, because of the risks of price increases and schedule delays for the NGCCs, if approved, the Companies should provide quarterly updates to the Commission about key milestones achieved and challenges encountered and the costs of these units. Clear and open communication will help facilitate more expedient and informed action if circumstances change and warrant a pivot in direction or a re-evaluation of the decision to pursue these units.

The Companies also need to plan for a scenario that complies with EPA's recently

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[36] *See, e.g.*, NESP, *National Standard Practice Manual: For Benefit-Cost Analysis of Distributed Energy Resources Summary*, Table S-3 (Aug. 2020), https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-Summary_08-24-2020.pdf.

[37] See a potential framework for conducting this assessment here: EPRI, *Grounding Climate Risk Decisions: Physical Climate Risk Assessment Scientific Foundation and Guidance for Companies* (Dec. 2022), https://www.epri.com/research/programs/109396/results/3002024246.

proposed greenhouse gas ("GHG") rules for power plants (the "Proposed New GHG Rules") and should file that plan with the Commission with its next IRP.

VI. PROPOSED NEW GHG RULES

Q. What are the "Proposed New GHG Rules"?

A. In simplest terms, the Proposed New GHG Rules would establish Clean Air Act ("CAA") emission limits and guidelines for carbon dioxide from fossil fuel-fired power plants. Section 111 of the CAA requires the U.S. Environmental Protection Agency ("EPA") to establish standards for large emission sources based on the application of the "best system of emission reduction" ("BSER") that are adequately demonstrated considering cost, energy requirements, environmental impacts, and other statutory factors.[38] Pursuant to that requirement, on May 11, 2023, EPA proposed new GHG emission limits and guidelines for new and existing coal and natural gas-fired power plants.[39] Specifically, EPA proposed standards for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion Electric Generating Units ("EGUs") based on hydrogen co-firing and CCS, and is simultaneously proposing to establish new emission guidelines for existing fossil fuel-fired steam EGUs that reflect the application of CCS and the availability of natural gas co-firing.[40] On May 23, 2023, the proposed new GHG rules were published in the Federal Register. EPA has announced the intention to finalize the Proposed New GHG Rules by April 2024 after considering the comments submitted this

[38].42 U.S.C. § 7411(a)(1), (b), (d).
[39] U.S. Envtl. Prot. Agency, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (May 23, 2023).
[40] *Id.* at 33,243.

summer.[41]

Q. What do the Proposed New GHG rules require for new natural gas EGUs?

A. For new natural gas EGUs, the Proposed New GHG Rules would require baseload natural gas turbines with a capacity factor greater than 50% to co-fire 30% hydrogen by 2032 and 96% hydrogen by 2038, or to install and utilize CCS with a 90% CO_2 capture rate by 2035.[42] ~~For natural gas turbines with an intermediate load between 20% to 50% capacity factor, only 30% hydrogen co-firing by 2032 is required with no subsequent requirements.~~[~~43~~] For natural gas turbines with a low-load capacity factor of less than 20%, only the use of "lower emitting fuels" with a standard of performance of 120 lb to 160 lb CO_2 per MMBtu is required.[44]

Q. Did the Companies' modeling and other supporting analysis for this case take the Proposed New GHG Rules into account?

A. No, they did not. The Proposed New GHG Rules were not released by EPA until after the Companies made their initial filings in both Case No. 2022-0402 and Case No. 2023-00122.

Q. Have the Companies stated a position on how the Proposed New GHG Rules, if finalized, would likely affect their proposal to construct two new NGCCs?

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[41] White House Office of Mgmt. & Budget, Office of Info. & Reg. Affairs, Spring 2023 Unified Regulatory Agenda, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2060-AV09.

[42] 88 Fed. Reg. at 33,288, 33,322.

~~[43] Id.~~

[44] *Id. See also* EPA, Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf (accessed June 13, 2023) (Table on slide 8 summarizing the proposed new GHG NSPS for new natural gas EGUs and Table on slide 13 summarizing the proposed new GHG rule for existing EGUs).

A. Not completely. In response to KCA request 3-3, the Companies assert that the Proposed New GHG Rules "do[] not require carbon dioxide ("CO2") capture and sequestration ("CCS") or hydrogen co-firing per se for new gas-fired units."[45] For baseload gas-fired units, the Companies maintain that nothing would be required prior to 2032 other than achieving CO_2 emissions of no more than 770 lb/MWh gross, which the Companies state the proposed NGCC units will be capable of achieving.[46] Then, beginning in 2032, the Companies assert the proposed NGCCs have three options for compliance: (1) reducing capacity factor and operating as an intermediate-load unit indefinitely (which has a CO_2 emission restriction of no more than 1,000 lb/MWh-gross), (2) meeting the lowered 680 lbs per MWh-gross CO_2 emission standard, which EPA has stated will be achievable by co-firing low-GHG hydrogen, or (3) meeting the 90 lb/MWh-gross CO_2 emission standard, which EPA has stated will be achievable through the CCS path, which does not require CCS to be operational until 2035. However, the Companies do not identify which of these compliance pathways they would likely choose, stating that "it is not clear at this time how the Companies would choose to utilize generation technologies" at the proposed NGCCs to comply with the Proposed New GHG Rules, "[g]iven the other large changes in the Companies' generation portfolio that would result" from EPA finalizing the rules.[47] Nor do the Companies make any attempt to quantify the costs of any potential

[45] Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Kentucky Coal Association's Second Supplemental Request for Information, Question 3 (May 31, 2023) ("LGE & KU Response to KCA Second Supplemental Q3"). *See also* LGE & KU Response to JI Third Data Request Q20 (reiterating the same assertion).
[46] The Proposed New GHG Rules would require, however, that the Companies notify EPA by January 1, 2031, which of the three 2032 compliance pathways they intend to follow. 88 Fed. Reg. at 33,326.
[47] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint

pathway for the proposed NGCCs to comply with the Proposed New GHG Rules or analyze any further the many other implications that the Proposed New GHG Rules would have for their resource planning.

Q. What costs may the proposed NGCCs incur because of the Proposed New GHG Rules?

A. The costs are unknown. In response to Joint Intervenors' Request 3-17(a) and (c), the Companies state that they have not estimated the required costs for the proposed NGCC units to co-fire hydrogen and have not evaluated other costs associated with the proposed NGCCs burning hydrogen because the hydrogen resources are not currently available, and the costs are unknown.[48] But, in response to Joint Intervenors' Request 3-17(b), the Companies explain that to accommodate hydrogen, "[a]t a minimum, future infrastructure changes would be needed that include new or upgraded combustors, upgraded gas supply piping size and material of construction, larger gas turbine enclosures, fuel blending skids, larger Heat Recovery Steam Generators ("HRSG") to accommodate additional Selective Catalytic Reduction ("SCR") equipment, as well as significant upgrades to existing natural gas pipelines to support the supply and transport of hydrogen." The Companies also state, however, in response to Joint Intervenors' Request 3-18(c), that by limiting a unit's annual capacity factor, it is possible to comply with the proposed new GHG rules without an increase in the capital cost of the proposed units. To do so however, is a significantly different economic proposition than that modeled by the

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Intervenors' Third Set of Data Requests, Question 11(b) (May 31, 2023) ("LGE & KU Response to JI Third Data Request Q").

[48] *See also* LGE & KU Response to JI Fourth Data Request Q16, stating that Companies' April 25th Request for Proposals to NGCC unit vendors was issued so the responses will include OEM-specific quantifications of on-site costs to attain defined bands of hydrogen co-firing.

Companies for this case, which tended to result in a capacity factor of about [BEGIN CONFIDENTIAL [redacted]%. END CONFIDENTIAL].[49]

Q. Are there concerns around whether the Companies' proposed NGCCs will be able to co-fire with hydrogen to comply with the proposed new GHG rules?

A. Yes, and the Companies acknowledge this. The Companies have described their proposed NGCCs as "hydrogen ready, meaning [that the] additional infrastructure will be in place or can be accommodated with minimal modifications after commercial operation" to allow for 30-50% hydrogen blending.[50] However, in response to Joint Intervenors' Third Data Request Question 13, the Companies state that they "have not speculated on"[51] whether the proposed 2038 hydrogen co-firing standards, which require 96% hydrogen blending for baseload units, are achievable. The Companies further acknowledge that sufficient supplies of green hydrogen (the fuel source needed to comply with the hydrogen requirements of the Proposed New GHG Rules) are not currently available, nor have the Companies offered any indication that they have a firm plan for acquiring the necessary green hydrogen should they opt for that compliance pathway.[52]

Q. Should the proposed new GHG rules have an impact on the Commission's review of the Companies' requests in this case for CPCN approval of two proposed NGCCs?

A. Undeniably yes. If finalized, the Proposed New GHG Rules would require major, transformative changes in the Companies' supply-side resource portfolio. The

[49] SAW Confidential Workpapers, CONFIDENTIAL_03_PROSYM, Phase 3.
[50] Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Attorney General's Initial Request for Information, Question 22 (Mar. 10, 2023) ("LGE & KU Response to AG Initial Q").
[51] LGE & KU Response to JI Third Data Request Q13.
[52] *See, e.g.*, LGE & KU Response to JI Third Data Request Q11(b).

Companies' reference to EPA's own modeling to support its contention that the Proposed New GHG Rules "support rather than undermine the Companies' proposals in this proceeding"[53] is extremely speculative, given all of the uncertainties noted with how the Companies would be able to comply with the Proposed New GHG Rules, the macro nature of the modeling conducted by EPA, and the effects that it would have on their remaining supply-side resources. And as discussed elsewhere in my testimony, regardless of whether the Proposed New GHG Rules or some other form of requirement to reduce CO_2 emissions is adopted in the U.S., the Companies' failure to take that likely future scenario into account in their modeling is a significant weakness in their analysis.

Q. Do the proposed new GHG rules increase the degree of uncertainty about the modeling evidence in this case?

A. Yes. In response to Staff Request 5-2, the Companies state that they do not have necessary information needed to perform an accurate analysis of the effect of compliance with the Proposed New GHG Rules and they cannot model hypothetical investment alternatives for which they do not possess real, actionable proposals or cost estimates. Nevertheless, the Companies "stress test" their portfolio by assuming a 50% capacity factor for the new NGCCs beginning in 2032 and a $25 per ton carbon price for existing coal in 2030. While this was a good faith attempt to model the EPA rule requirements on an extremely short timeframe it falls short with respect to evaluating a non-fossil replacement for the retiring coal units. The only non-gas resources available in the model for resource selection for the entirety of the planning period through 2050 are resources

[53] LGE & KU Response to KCA Second Supplemental Q3.

that responded to the Companies' 2022 RFP and even then, only a subset are included. Even if the Companies had reoptimized each portfolio, which they do not appear to have done, it does not make sense to limit the optimization over this period to those choices because there will certainly be more projects developed and because their costs could be materially differ particularly if supply and demand equilibrate in the renewable and battery markets. It makes sense that the NGCCs would be cheaper than operating the coal units under these assumptions, but it does not fully test a renewable alternative to the NGCCs operating at a 50% capacity factor. Nor did the Companies test the impact of these dispatch changes on the reliability of the portfolio with the two NGCCs.

VII. INCLUSION OF DERs IN THE MODELING

Q. With the exception of DR, DERs are not represented explicitly in the Companies' modeling for this case. What changes would be necessary to more robustly include those resources?

A. From a planning perspective, I do think it is important to represent those resources explicitly in the modeling. It is the most transparent approach and provides more opportunities for those resources to be included in an optimal plan. However, those resources can easily be overly constrained by market potential studies which have significant pitfalls.[54]

Mr. Grevatt discusses other steps the Companies ought to take to leverage additional energy efficiency and DR resources. But it is important the Companies begin to think comprehensively about the value such measures can provide to alleviate demand during

[54] Chris Kramer & Glenn Reed, *Ten Pitfalls of Potential Studies*, Energy Futures Group. (Nov. 2012), https://www.raponline.org/wp-content/uploads/2016/05/energyfutures-kramerreed-tenpitfallsesdraft2-2012-oct-24.pdf.

extreme events and to not constrain the measures based on adoption rates that are guided merely by simple payback calculations since there are many reasons, beyond cost, that customers adopt DERs.

There may be significant reliability benefits to gain or risk to avoid in pursuing these measures. As Mr. Stuart Wilson noted in his testimony, "DSM is . . . markedly more cost-effective than SCCT for enhancing the reliability of these portfolios."[55] The approach the Companies used to determine this could be extended to other resources including energy efficiency, customer sited generation or storage, and could even be extended to determine the characteristics of resources that would help improve or meet reliability criteria such as seasonality and duration.

The Companies' reliability modeling shows once its planned solar is added, its system shifts to more wintertime risk in the overall LOLE. And in response to discovery, the Companies stated that it was their belief that "electric heating was the primary driver of the increased LG&E and KU customer demand" during Winter Storm Elliott. It is important for the Companies to be curious about what drives load during these events and confirm its belief so that we are making informed decisions about how to manage these particular loads. If true, the Companies' most recent appliance saturation study would suggest that a minority of the Companies' residential load is responsible and that there is significant work to do in order to make sure this problem is not exacerbated as more heating load transitions to electricity.

Currently, about 40% of residential customers use heat pumps, electric furnaces, electric

[55] Wilson Direct at 33.

space heaters, and baseboard heating in their homes.[56] Those technologies are ordered from most to least numerous in the responses to the survey. Those customers using electric resistance heating equipment are good candidates to move to cold climate heat pumps and to reduce load during extreme winter events and should ideally be incentivized to conduct cost-effective weatherization as well. Modeling such a program to do this may show more value in SERVM than in PLEXOS. The PLEXOS load is summer peaking only, while SERVM load includes several years with winter peaks.

VIII. MANAGING SOLAR EXECUTION RISK

Q. The Companies offer ownership as a key mechanism to reduce solar execution risk, would you agree?

A. If local zoning approvals are a major factor in stymieing project execution and the Companies are truly "exempt from planning and zoning" law[57], then, yes, Company ownership is an important risk reduction mechanism. It is, however, not the only mechanism and not the only step the Companies can take to facilitate project success.

The Companies have a critical role in communicating the importance and benefits of its selected projects to the local community and in trust building between the host communities and the developers. In future RFPs, they can signal their preference for projects that can demonstrate early and active community engagement and have a plan to help transfer project benefits to the community such as by providing grants to the host community for distributed solar and battery projects.

[56] *See* LGE & KU Response to JI Initial Q64. Note that the survey appears to be the result of a mailer sent to customers. It is not clear what steps, if any, the Companies took to make sure the results were statistically significant.
[57] Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Mercer County Fiscal Court's Initial Request for Information, Question 14 (Feb. 17, 2023).

The Companies can also rely more on build/own/transfer ("BTA") agreements such as the one they are using to execute the Marion County project [BEGIN CONFIDENTIAL [redacted]. END CONFIDENTIAL][58]

Finally, the Companies can allow other actors to bring solar online within its service territory by offering net metering beyond the 1% minimum and/or encouraging participation in and even offering programs to incentivize solar generation for customers of all classes. This would help the Companies make up any gaps created by the failure of particular projects to reach their commercial online date.

Notably, solar plays a significant role in reducing summertime loss of load risk and should be thought of as a risk reduction measure, given that without it the Companies' system is still weighted towards higher summer than winter resource adequacy risk. The Companies' SERVM modeling shows that its proposed 1,127 MW of solar reduces the summer risk for a portfolio with the two NGCCs from 1.32 to 0.09.[59]

IX. COMPLIANCE WITH SB 4

Q. Do you have any recommendations to make with respect the requirements of SB4 on the Companies' planned retirements?

A. Yes. One provision of Senate Bill 4 requires that a retiring EGU be replaced with new capacity that "[m]aintains or improves the reliability and resilience of the electric transmission grid." The Companies use SERVM to measure the reliability of replacement portfolios and determine each portfolio's LOLE metric. I agree that establishing a

[58] Wilson Workpapers, CONFIDENTIAL_20221209_ResourceScreeningModel_0308.xls.
[59] Wilson Direct, Exhibit SAW-1 at 37, 38.

minimum reliability standard and evaluating portfolios against that standard is a good practice and, giving a non-legal opinion only, appears to be consistent with the language of the law. However, it is important to be clear about what SERVM is not presently analyzing. Specifically, there is no analysis that evaluates these portfolios for risk associated with climate change. Even as that risk relates to load caused by temperature changes, the risk captured in SERVM is muted because it weighs all weather years going back to 1973 equally. As I explained above, the risk to electric power systems from climate change is not just economic but also physical and not well defined in planning analyses. It would be important to improve the Companies' SERVM modeling to capture this risk as best as possible and to supplement its risk analysis with a climate change risk assessment that looks at infrastructure across the Companies' electric system.

Second, it is not clear if the language of the bill quite literally intends to ignore the distribution system and focus only on the transmission system, if so that would be a serious omission with respect to reliability because customer outages are much more likely to be a product of failures on the distribution system than at the bulk level. The Companies' SERVM model does not currently simulate distribution system outages and I am skeptical that it could be set up to do so. However, the analysis that satisfies this requirement could be supplemented by a distribution specific analysis. And incorporation of resources that improve reliability on the Companies' distribution system would be appear to provide significant benefit because there are several counties in the Companies' service territories that have experienced seven or more annual average outages *lasting eight hours or more* over a three-year period as shown in Figure 85.

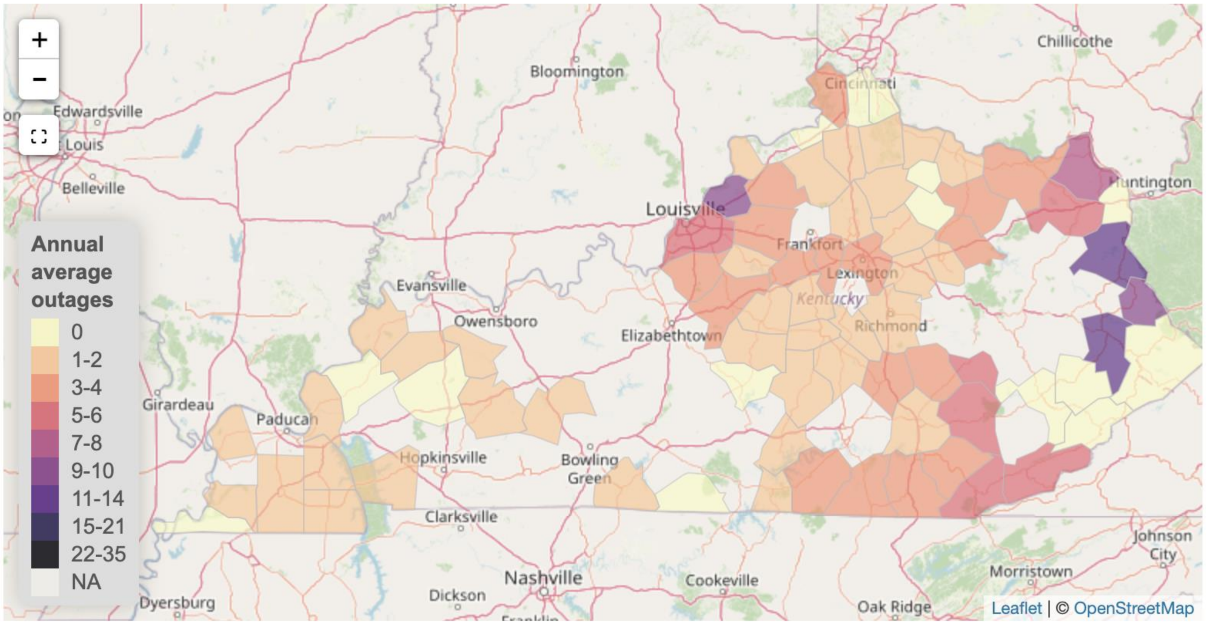

Figure 85. Count of Annual Average Outages Exceeding 8 Hours[60]

Oldham County in the Louisville metro area is the county that experiences the most 8+ hour outages with an average of 10 per year over the period analyzed. Because of the length of these outages and, again, the much higher frequency of distribution system outages, DERs need to be a part of the Companies' planning in much greater number and also evaluated for their impact on reliability at the distribution level for purposes such as this case.

Q. Does this conclude your testimony?

A. Yes.

[60] Vivian Do et al., *Spatiotemporal distribution of power outages with climate events and social vulnerability in the USA*, 14 Nat. Commun. Article 2470 (Apr. 29, 2023), https://doi.org/10.1038/s41467-023-38084-6.