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**

DIRECT TESTIMONY OF
CHARLES R. SCHRAM
DIRECTOR, POWER SUPPLY
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 15, 2022

INTRODUCTION

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

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

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission in previous cases, most recently in the Companies' Integrated Resource Plan and Fuel Adjustment Clause hearings.[1] I have also testified in the Companies' Environmental Cost Recovery ("ECR") proceedings.[2]

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to discuss the Companies' June 2022 Request for Proposals ("RFP") for capacity and energy, the nature of the responses, the commercial transactions resulting from the Companies' analyses, and the current status of those transactions. I also address the natural gas supply considerations for the two natural

---

[1] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, July 13, 2022 H.V.T. at 13:38:00-14:34:10 (Ky. PSC Oct. 7, 2022); *Electronic Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2016, through October 31, 2018*, Case No. 2019-00004, Direct Testimony of Charles R. Schram (Feb. 25, 2019); *Electronic Examination of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company from November 1, 2016, through October 31, 2018*, Case No. 2019-00005, Direct Testimony of Charles R. Schram (Feb. 25, 2019).

[2] *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2016-00026, Direct Testimony of Charles R. Schram (Jan. 29, 2016); *Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2016-00027, Direct Testimony of Charles R. Schram (Jan. 29, 2016).

gas combined cycle ("NGCC") units for which the Companies are seeking certificates of public convenience and necessity ("CPCNs") in this proceeding.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring two exhibits:

Exhibit CRS-1	June 2022 RFP
Exhibit CRS-2	June 2022 RFP Responses

Q. Please describe your responsibilities as Director of Power Supply.

A. As Director of Power Supply, I am responsible for real-time generation dispatch, natural gas purchases for generation, and commercial transactions. Power Supply's operations team performs the real-time generation dispatch function to reliably serve the Companies' customers at every moment. The Companies have experienced hourly winter load that varies up to 2,760 MW in a day and hourly summer load that varies 3,220 MW in a day. Furthermore, intra-hour load can swing by several hundred megawatts over the course of an hour and more than 100 MW over a period of seconds, highlighting the importance of generation assets with ramping capabilities to meet these changes in demand. Generation dispatchers monitor all available resources' response abilities. This includes load control programs that must reliably reduce energy demand per design specifications.

Power Supply purchases all of the natural gas to fuel the Companies' Cane Run 7 NGCC unit and all peaking combustion turbines ("CTs"). As detailed later in my testimony, the Companies hedge gas supply for Cane Run 7 to reduce customers' bill volatility by purchasing a portion of the unit's gas supply on a forward basis.

Power Supply is also responsible for commercial transactions involving generation. On a daily basis, the Companies purchase or sell non-firm energy when economic and system conditions are favorable. In addition, I led negotiations for the Companies' first two solar power purchase agreements ("PPAs") executed in 2019 and 2021. I was also responsible for administering the Companies' tolling agreement for the Bluegrass CTs from 2015-2019.

Part of Power Supply's commercial responsibilities includes formulating and issuing RFPs, working with RFP respondents regarding their responses, and conducting negotiations with RFP respondents to arrive at appropriate commercial arrangements and contracts. In my role as Director of Power Supply, I am therefore quite familiar with and have personal knowledge of the Companies' most recent RFP, RFP responses, and discussions with RFP respondents.

OVERVIEW OF THE COMPANIES' JUNE 2022 RFP

Q. Why did the Companies issue an RFP for electric capacity and energy in June 2022?

A. As described in greater detail in the testimony of David S. Sinclair and Stuart A. Wilson, the Companies became increasingly certain they would have a capacity need no later than 2028 following the April 2022 issuance of the U.S. Environmental Protection Agency's Good Neighbor Plan concerning nitrogen oxides ("NOx") emissions. Mr. Sinclair directed Power Supply to issue an RFP to obtain capacity and energy offers for Mr. Wilson's group (Generation Planning) to evaluate in the Resource Assessment described in Mr. Wilson's testimony.

Q. What was the content, timing, and distribution of the Companies' June 2022 RFP?

A. On June 22, 2022, the Companies issued an RFP for capacity and energy, including energy storage, with a minimum nameplate value of 100 MW available no sooner than 2025. The Companies provided no specification for desired technologies. Storage facilities were requested to have a minimum nameplate of 100 MW and be available for at least four hours, i.e., capable of at least 400 MWh of stored energy. Responses were due on August 17, 2022, giving potential respondents eight weeks to respond. The RFP was sent to 146 potential respondents across broad sectors of the electric generation and storage industries, in addition to a number of industry publications and organizations.[3] The Companies also issued a press release on June 22, 2022 containing a link to the RFP on the Companies' website.[4] News of the press release circulated in the industry, including in the widely read S&P Global *Market Intelligence*.[5]

Q. Please describe the RFP responses the Companies received.

A. A total of 22 parties responded to the RFP with 39 projects. Many of the projects had multiple options for term, size, or proposed commercial operation date, resulting in a total of 101 proposals, all of which our group delivered to the Generation Planning group for analysis, which Mr. Wilson discusses.[6] The table below provides the number of respondents by technology contained in the offers.

---

[3] The Companies provided their RFP to the Electric Power Supply Association (EPSA), Energy Central, Environmental Leader, North American Energy Marketing Association (NAEMA), Solar Energy Industries Association (SEIA), and Wind Energy Association.

[4] The Companies' June 22, 2022 press release concerning the RFP is available at https://lge-ku.com/newsroom/press-releases/2022/06/22/lge-and-ku-request-proposals-generation-they-look-toward-clean. The link to the RFP became inactive shortly after the RFP due date.

[5] S&P Global, Market Intelligence, "PPL utilities seek proposals to replace coal-fired capacity for Ky., Va." (June 23, 2022), available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ppl-utilities-seek-proposals-to-replace-coal-fired-capacity-for-ky-va-70919084. *See also, e.g.,* Smart Grid Observer, "LG&E and KU Request Proposals for Generation as They Look Toward a Clean Energy Future" (June 27, 2022), available at: https://smartgridobserver.com/industry-news/lg-e-and-ku-request-proposals-for-generation-as-they-look-toward-a-clean-energy-future.

[6] As Mr. Wilson notes in his testimony and the 2022 Resource Assessment, the Companies later subdivided some of the proposals into a total of 110 options reviewed.

Technology	Number of Respondents
Solar	12
Solar w/ Battery	6
Battery Only	6
Pumped Hydro Storage	1
Wind	1
NGCC	1
Simple-cycle CT	1
Solar (Asset Development Offer)	2

The Companies' Project Engineering group provided the only responses for fossil fueled resources, including the two NGCC units for which the Companies are seeking CPCNs in this proceeding, one at the Mill Creek Generating Station (i.e., Mill Creek Unit 5 ("Mill Creek NGCC") and the other at the E.W. Brown Generating Station (i.e., Brown Unit 12 ("Brown NGCC")).[7]

Q. Did the RFP responses consider the impacts of the federal Inflation Reduction Act ("IRA")?

A. Yes. Although the IRA was signed into law on August 16, 2022, just before the RFP response deadline of August 17, the legislation's contents were broadly discussed in the industry prior to the IRA's final passage.[8] Though most respondents indicated that they considered IRA impacts in their August 17, 2022 offers, the Companies gave respondents an additional opportunity to update their offers by September 30, 2022. Five respondents provided updated information.

Q. What were the trends in solar pricing compared to the Companies' prior RFP in 2021?

---

[7] All references to "Mill Creek" herein are to the Mill Creek Generating Station, and all references to "Brown" herein are to the E.W. Brown Generating Station.

[8] After the IRA's introduction in September 2021, the U.S. House of Representatives passed the IRA in November 2021. Nine months later the Senate began considering the bill on August 2, 2022, and passed it on August 7, 2022. The House agreed to the Senate's amended version on August 12, and the President signed the IRA into law on August 16. *See* https://www.congress.gov/bill/117th-congress/house-bill/5376/all-actions.

A. Despite the IRA legislation, respondents' solar PPA offer prices were generally at least 30 percent higher than similar offers the Companies received in response to their 2021 RFP. Discussions with respondents revealed ongoing concerns about supply chain constraints, solar component tariffs, rising interest rates, and overall inflation. Among other things, respondents indicated that these issues resulted in higher polysilicon and solar panel pricing.

The Companies' observed increases in RFP pricing are consistent with recent market trends. For example, according to LevelTen Energy's PPA Price Index for North America, solar P25 PPA prices stand at $42.21 as of October 2022,[9] 34 percent higher than the same period one year earlier.[10] P25 prices represent the 25th percentile of price quotes, so 75 percent of the quotes were above the P25 price level. Therefore, the responses to the Companies' are generally consistent with market trends.

<u>SELECTED OFFERS</u>

Q. What was the Companies' process for evaluating the RFP responses?

A. Under my supervision, the Companies' Power Supply group reviewed each RFP response for the required data and addressed any missing information with the applicable respondent(s). We then submitted the data to the Generation Planning group for analysis. Mr. Wilson's testimony describes the analysis Generation Planning used to evaluate the RFP responses and to select responses to pursue. After Generation Planning completed its analysis and selection process, Power Supply began commercial discussions with the selected bidders.

[9] *See* LevelTen Energy "Q3 2022 PPA Price Index Executive Summary North America" at 7, available at: https://www.leveltenenergy.com/ppa.

[10] "Solar PPA Prices Soar Again in Q3", Solar Builder Magazine, Solar PPA prices soar in Q3: When will IRA impact the market? (solarbuildermag.com), October 18, 2022

Q. In addition to the supply-side resources discussed by Mr. Sinclair for which the Companies are seeking CPCNs, which solar power purchase transactions are the Companies pursuing?

A. The Companies are advancing four solar PPAs, which are listed below with their forecasted commercial operation date:

1. BrightNight Power "Gage Solar PPA" 115 MW AC in Ballard County, 12/31/2026
2. Clearway "Song Sparrow PPA" 104 MW AC in Ballard County, 12/31/2026
3. ibV "Grays Branch PPA" 138 MW AC in Hopkins County, 1/15/2026
4. ibV "Nacke Pike PPA" 280 MW AC in Hardin County, 1/15/2026

Q. How do the selected solar PPA offers compare to current market prices?

A. Prices for the PPAs selected by the Companies are consistent with the October 2022 LevelTen solar P25 market prices I discussed above.

TRANSACTION STATUS

Q. What is the status of the solar PPA transactions that are described in the CPCN?

A. The Companies have conducted extensive commercial negotiations with BrightNight Power, Clearway, and ibV for the four solar projects totaling 637 MW AC listed above. It is my current expectation that we will be able to reach agreements with all of the developers, and I anticipate the Companies will execute final PPAs with all of the developers by the end of January 2023.

Q. How do these PPAs differ from the Companies' prior solar PPAs for the Rhudes Creek and Ragland solar projects?

A. The Rhudes Creek and Ragland PPAs are relatively straightforward PPAs with flat pricing and no provisions for renegotiating those prices. Two of the four new PPAs are similar in that they are non-indexed price contracts without price-reopener provisions.

But as I discussed earlier in my testimony, solar prices have increased significantly. If that trend continues, a PPA with today's prices may not support a developer's ability to obtain financing at the appropriate time. Financing is typically obtained months after the PPA is executed, subsequent to local permitting and State Siting Board approvals. Thus, unlike the Rhudes Creek and Ragland PPAs, the other two PPAs the Companies are now working to finalize contain provisions for a review of the solar pricing prior to the developer obtaining financing for the project. More specifically, these two PPAs contain a 60-day price re-opener period that can be instigated by either party just prior to the project moving to the financing stage. This will allow the Companies to request a lower price if solar costs and interest rates decline, and the solar developer may request a higher price if solar costs, interest rates, or both increase such that the project would not be financeable at the price agreed to at PPA execution. If the parties cannot agree on a new price by the end of the 60-day period, the original PPA price would stay in place and either party would have 30 days to terminate the PPA.

Q. Are the Companies pursuing any battery storage projects proposed by third parties?

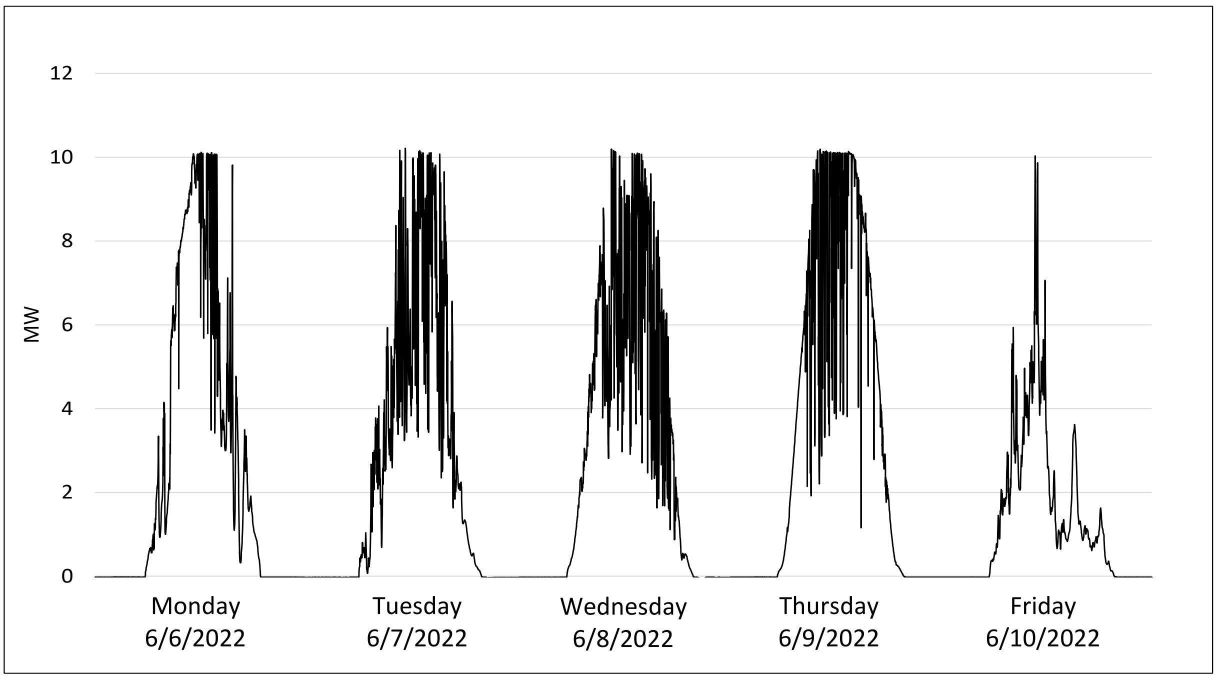
A. Mr. Wilson's testimony and the 2022 Resource Assessment (Exhibit SAW-1) address the economics of battery storage. Based on those economics, the Companies are not pursuing any battery storage offers received from third parties in the RFP. But as Mr. Sinclair discusses, the Companies are proposing to self-build a 125 MW, 500 MWh battery energy storage system at Brown ("Brown BESS") to further explore and understand the system impacts and benefits of large battery energy storage systems.

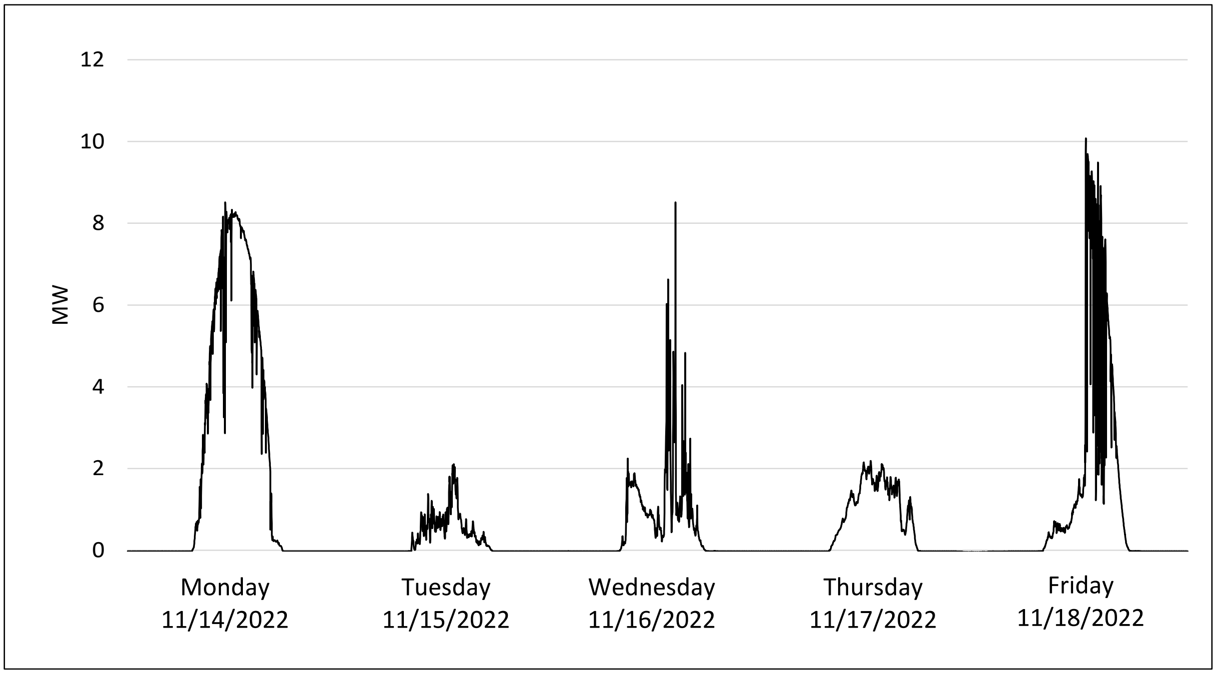
Q. What system benefits does battery storage offer?

A. In addition to serving as resources to meet spinning reserve operational requirements, battery storage will potentially become a required tool in managing system regulation and supporting reliability in an environment of increasing renewables penetration. From my perspective as the Director of Power Supply, which includes real-time generation dispatch responsibilities, the integration of hundreds or thousands of megawatts of solar capacity will require the ability for dispatchable units to quickly ramp up and down as cloud cover moving across solar facility locations creates solar energy intermittency. In addition to the ramping capabilities of on-line units, the ability to use battery energy storage systems to move energy in time for durations much shorter than overnight periods will become increasingly important for system stability and for meeting customers' energy demands every moment of the day. For example, the graphs below show real-time data from the Companies' Brown solar facility for weekdays this past June and November. While the reduced solar energy output during the shorter and typically cloudier November days is expected, one can also easily see that clouds impact the minute-to-minute output of the facility even during the longer daylight periods and typically sunnier summer days in June.[11] Note that Monday, June 6, started as a mostly sunny day, but intermittent clouds caused solar output variation by afternoon. Friday, however, had reduced sunshine most of the day except for a brief

[11] All of the 1-minute data associated with the Brown solar facility is located at https://lge-ku.com/live-solar-generation.

midday clear period. Tuesday through Thursday of that week experienced ongoing intermittent clouds throughout each day. During the week of November 14, Monday's output saw less variation, while Tuesday and Thursday were largely cloudy days. Wednesday and Friday experienced only brief periods of clearing that enabled solar output to spike. These examples demonstrate the value of systems like Brown BESS in integrating generation like that illustrated below in hundreds or even thousands of megawatts.





<u>**STATUS OF PRIOR PPAS**</u>

Q. What is the status of the Companies' existing solar PPAs for Rhudes Creek and Ragland?

A. Both the Rhudes Creek and Ragland solar projects are still seeking local approvals. The Companies executed the PPA for the ibV's 100 MW AC Rhudes Creek project in 2019; it has been approved by the State Siting Board subject to specific conditions related to local approvals and construction. The Companies executed the PPA for BrightNight's 125 MW AC Ragland project in 2021. BrightNight is seeking local approval for the project, but BrightNight has not yet submitted the project to the State Siting Board.

As I noted earlier in my testimony, solar prices have increased. The pricing in the Rhudes Creek and Ragland PPAs is now significantly below the current market price for solar. The Companies still assume that these projects will be constructed. But although the PPAs contain provisions for the Companies to recoup limited financial damages in the event of a developer's breach of contract obligations, a developer's inability to obtain financing for a project does not constitute such a breach under the PPA agreement. Thus, if the developers cannot obtain financing for the projects at the prices specified in the PPAs, the developers will not build the projects, at least until economic conditions change sufficiently to allow the projects to obtain financing at the PPA-specified prices. This is an example of the solar project execution risk Mr. Wilson discusses in his testimony and the 2022 Resource Assessment.

NATURAL GAS SUPPLY FOR PROPOSED NGCC UNITS

Q. Is firm gas transportation service available for the NGCC units (Mill Creek NGCC and Brown NGCC) included in the CPCN?

A. Yes. The Companies have held discussions with the pipelines serving Mill Creek and Brown and concluded that sufficient firm gas transportation services will be available to reliably deliver natural gas to fuel the proposed NGCC units. Mill Creek NGCC will be served by the Texas Gas Transmission ("Texas Gas") interstate pipeline, while Brown NGCC will be served by either the Texas Eastern or the Tennessee Gas pipeline. Fuel supply reliability for the existing Brown simple cycle combustion turbines ("SCCTs") is currently supported by access to the two pipelines and fuel oil backup for six of the seven SCCTs. But Brown NGCC will require a suite of firm transport services similar to Mill Creek NGCC. Ongoing discussions with both Texas Eastern and Tennessee Gas will determine the optimal pipeline supplier for firm transport services. To ensure firm transportation services are available for both Mill Creek NGCC and Brown NGCC, execution of contracts with Texas Gas and Texas Eastern or Tennessee Gas is anticipated in the first quarter of 2023 if a satisfactory regulatory exit provision can be included in each contract.

Q. Would having Mill Creek NGCC's gas transportation service on the same interstate pipeline system as the existing Cane Run NGCC (Cane Run Unit 7) create a significant reliability risk?

A. The Texas Gas pipeline serving both sites is supported by an extensive system of multiple lines and compressors to ensure reliability. For example, in areas upstream and downstream from Louisville, piping and valves connect multiple lines approximately every ten miles and the system is supported by the redundancy of compression equipment, with 30 compressors located from northeast of Trimble County to southwest of Mill Creek. Texas Gas system flows in this area are bidirectional, with seasonal or more frequent changes of flow direction based on demand. Texas Gas's nine gas storage fields in western Kentucky and southern Indiana further support system reliability and supply flexibility. As an indication of system reliability and the absence of pipeline constraints and adverse events, Texas Gas has issued zero Operational Flow Orders over the last 15 years.[12] The Companies' experience with the reliability of Texas Gas's transport services to Cane Run and Trimble County has been excellent. Mill Creek NGCC will also be connected to the interstate pipeline system at a separate point than Cane Run Unit 7, eliminating a single contingency that would exist if the units were served from a single pipeline interconnection.

Q. Would the purchase of additional natural gas to fuel Mill Creek NGCC be practicable using the Texas Gas pipeline?

[12] An Operational Flow Order is a mechanism used by pipelines to alleviate conditions that could threaten safe operations or operational integrity of the system. These orders may also be issued to maintain operations required to provide efficient and reliable service.

A. The Companies do not anticipate any issues procuring natural gas on the spot and forward markets for delivery on the Texas Gas pipeline. To hedge against fuel price volatility for Cane Run Unit 7, the Companies currently purchase up to 50 percent of the unit's forecasted gas burn on a forward basis for the current year. The balance of natural gas is purchased daily on the spot market. For the following years one, two, and three the Companies purchase 40-60 percent, 20-40 percent, and 0-20 percent, respectively, of the unit's minimum forecasted burn on a forward basis.

Q. Do the Companies anticipate developing a gas price hedging plan for Mill Creek NGCC and Brown NGCC, just as they have for Cane Run Unit 7 as you described above?

A. Yes. Managing our customers' fuel price risk is important, which is why the Companies have the hedging plan I discussed above for Cane Run Unit 7. Similarly, the Companies will review and potentially update their forward gas purchase plans with the addition of Mill Creek NGCC and Brown NGCC to ensure a prudent mix of spot and forward purchases to continue to reduce fuel price volatility for customers and address operational considerations for the units.

Q. What are the operational characteristics of the Texas Eastern and Tennessee Gas pipelines, and what is the Companies' current commercial relationship with those pipelines?

A. The Texas Eastern pipeline system consists of 8,580 miles of pipeline connecting the Gulf Coast to markets in the northeastern U.S., while the Tennessee Gas system includes 11,760 miles of pipeline connecting the Gulf Coast and Mexico to the northeastern U.S. The Texas Eastern pipeline has bidirectional capability with 2 Bcf per day flowing past the Brown area. Tennessee Gas has between one and two Bcf/day flowing through the area. The Companies have ongoing commercial transactions for gas transport to the Brown SCCTs with both Texas Eastern and Tennessee Gas, but do not have long-term firm transport agreements with either of the pipelines. Additionally, the LG&E LDC has an agreement with Tennessee Gas for a portion of its gas transport requirements. The pipeline segment owned by the Companies that connects the interstate pipeline system to Brown would still be capable of connecting to the alternate interstate pipeline, regardless of the choice of either Texas Eastern or Tennessee Gas for the firm gas transport services for Brown NGCC. This would further support transport reliability during an interruption event on the pipeline selected for the transport service agreement.

Q. For Brown NGCC, would the purchase of firm gas transport services be limited to the new unit?

A. The Companies will procure the appropriate breadth of firm transport services for Brown NGCC while also considering potential transport benefits for the seven existing Brown SCCTs. Six of the seven SCCTs have dual-fuel capabilities for limited duration operation using fuel oil. The transport services for Brown NGCC should complement the transport needs for the peaking units. For example, the transport services could be shifted to the peaking units in the event of an outage on Brown NGCC.

Q. Could SEEM or other spot markets be used to meet the Companies' need for capacity and energy instead of constructing Mill Creek NGCC and Brown NGCC?

A. No. The Companies use spot purchases and sales to optimize energy costs and increase off-system sales, not for system reliability. SEEM is an intra-hour market designed to use available transmission capacity that would otherwise go unused. SEEM supplements existing hourly markets, including those in PJM and MISO. Like spot transactions in PJM or MISO, SEEM purchases and sales are non-firm and can be cut for any or no reason. As such, the Companies cannot rely on these purchases to reliably serve customers' energy needs or to meet NERC requirements for spinning reserves.

Q. How does the addition of Mill Creek NGCC, Brown NGCC, 877 MW of solar, and Brown BESS operationally replace the retirement of 1,194 MW of coal capacity with regard to real-time dispatch considerations?

A. NGCC specifications indicate that their favorable ramp rates, 75-80 MW/minute for NGCC versus less than 10 MW/minute for coal, will be a good fit operationally with the overall system and with the additional intermittent generation from hundreds of additional megawatts of solar. Brown BESS should demonstrate that using the stored energy from the battery will not only provide a rapid ramp rate for addressing solar intermittency, but also can be used instead of committing a comparably sized SCCT when the economics are favorable for an expected run of four hours or less.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Charles R Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of December 2022.

Judy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

APPENDIX A

Charles R. Schram

Director, Power Supply
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3250

Professional Experience

LG&E and KU

Director, Power Supply	2016 – Present
Director, Energy Planning, Analysis & Forecasting	2008 – 2016
Manager, Transmission Protection & Substations	2006 – 2008
Manager, Business Development	2005 – 2006
Manager, Strategic Planning	2001 – 2005
Manager, Distribution System Planning & Eng.	2000 – 2001
Manager, Electric Metering	1997 – 2000
Information Technology Analyst	1995 – 1997

U.S. Department of Defense – Naval Ordnance Station

Manager, Software Integration	1993 – 1995
Electronics Engineer	1984 – 1993

Education

Master of Business Administration
University of Louisville, 1995
Bachelor of Science – Electrical Engineering
University of Louisville, 1984
E.ON Academy General Management Program: 2002-2003
Center for Creative Leadership, Leadership Development Program: 1998

Civic Activities

The Housing Partnership – Board of Directors, 2017 – Present

Leadership Louisville – Bingham Fellows class of 2020

Chuck Schram
Director, Power Supply
Power Supply
O 502-627-3250

PPL companies

220 West Main Street
Louisville, KY 40202

June 22, 2022

Request for Proposals to Sell Electric Capacity and Energy (RFP)

Dear Colleague in the Development and Marketing of Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (together the "Companies") are evaluating alternatives to provide least-cost long-term supply of capacity and energy to serve our customers. The Companies are exploring additions no earlier than 2025 to enable the Companies to address potential EPA regulations, load growth, unit retirements, and diversification of the Companies' generation portfolio. These additions could include cost-effective firm peaking (including storage), intermittent non-firm renewable (with or without storage), and/or firm dispatchable baseload and load-following capacity and energy.

The Companies will consider proposals that are reliable, feasible, and represent the least-cost means of supplying our customers with capacity and energy. The Companies' analysis will include costs for transmission service, transmission upgrades (if any), and voltage support within the LG&E/KU Balancing Authority footprint and an assessment of the ability of each proposal to be delivered in a timely manner consistent with the Companies' capacity and energy alternatives. Each respondent should make its proposal as comprehensive as possible so that the Companies may make a thorough and definitive evaluation of the proposal's benefits to the Companies' customers without further contact with the respondent. However, the Companies reserve the right to request additional information.

Please provide your proposal consistent with the stated terms below. The resource(s) proposed in response to this RFP should provide a site-specific Generating Facility (which shall be defined for the purposes of this RFP as a device for the production and/or storage for later injection of electricity) that the Companies can designate as a Designated Network Resource (DNR), as such term is defined in the LG&E and KU Joint Pro Forma Open Access Transmission Tariff ("Companies' OATT").

This RFP is not a commitment to purchase and shall not bind the Companies or any affiliate of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which respondent(s), if any, to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses that respondents incur in connection with preparation of a response to this RFP or any requests for additional information associated with this RFP. The Companies will not reimburse respondents for their expenses under any circumstances, regardless of whether the RFP process advances to a successful conclusion or is abandoned by the Companies at the Companies' sole discretion.

1. **Background** – All proposals will be evaluated in the context of meeting customers' load in a reliable, least-cost manner. If the Companies determine that a proposal may be in the best interest of the Companies' customers, the Companies may enter into negotiations which may lead to the execution of a definitive agreement(s). The Companies will consider all applicable factors in evaluating proposals, including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the proposal; (ii) respondent's creditworthiness; (iii) if applicable, the operating history or the development status of respondent's Generating Facility, including, but not limited to, the site chosen, pipeline interconnection and route (if applicable), permitting, and the status of an interconnection to the transmission grid; (iv) the anticipated availability of the capacity and/or energy; and (v) all other factors, such as the cost of interconnection or transmission that may affect the Companies' ability to reliably and cost-effectively serve the Companies' customers.

2. **Requirements** – The Companies are interested in alternatives to procure capacity and energy no earlier than 2025, including cost-effective firm peaking (including storage), intermittent non-firm renewable (with or without storage), and/or firm dispatchable baseload and load-following capacity and energy. To be considered, each unique proposal and/or project **must**:

   2.1. Be deliverable to the Companies' transmission system;
   2.2. Qualify as a DNR according to the Companies' OATT;
   2.3. Have a minimum term of 5 years and a maximum term of 30 years unless ownership of the Generating Facility by the Companies is proposed;
   2.4. Have at least 100 MW of nameplate rated capacity (proposals smaller than 100 MW will not be considered);
   2.5. In the case of renewable and storage combined proposals, include a minimum of 100 MW capacity with four-hour battery storage (400 MWh);
   2.6. In the case of standalone energy storage, include a minimum of 100 MW of capacity and 400 MWh of energy; and
   2.7. Comply with all industry standards applicable to the technology being proposed, including, but not limited to IEEE Std 2800™-2022 for inverter-based resources.

   Multiple proposals from multiple respondents may be selected to achieve an optimal generation portfolio for the future. The capacity and energy under each proposal must be generated from a defined source, a specific unit, or specific units that will qualify as a DNR. A respondent proposing capacity and energy from a resource connected directly to the Companies' transmission system must conform to the generation interconnection procedures in the Companies' OATT and must obtain a generation interconnection agreement for the Generating Facility in a timely manner. Third party respondents should not assume access to, or utilization of, existing sites owned by the Companies for siting proposed project(s).

3. **Key Terms and Conditions** – Each respondent's proposal should contain the pricing, project location, resource type, fuel type, performance characteristic and guarantees, financial security, and all other proposed terms and conditions necessary for the Companies to evaluate the proposal without further communication with the respondent. **All necessary information must be provided through an electronic submission of the attached data form(s) that correspond(s) to the proposal's generation technology and offer type. A separate data form must be included for each offer relative to resource size, term, commercial operation date, technology and option paring, price structure, etc.** Note that such data forms may be utilized in any filings with regulatory agencies (such as the Kentucky Public Service Commission) related to this RFP.

4. **Project Description (Required Proposal Content)** – Each proposal must contain a complete description of the proposed generation technology, project location, operating characteristics, transmission system interconnection point, etc.

5. **Pricing Details (Required Proposal Content)** – Proposed prices must be clear and quoted in U.S. dollars. If proposed pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included. Likewise, if the proposed pricing is cost-based, the nature of the costs to be included must be clearly stated. Each proposal must include the location of the Generating Facility but should NOT include transmission delivery costs for the proposed term across electric transmission systems. Respondents should assume the Companies will be responsible for all transmission costs that may be incurred to move the capacity and/or energy from the Generating Facility to, and on, the Companies' transmission system.

6. **Metering and Monitoring (Required Proposal Content)** – The Companies may require real time metering and monitoring of all generation resources. If so, the Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time metering and monitoring. The respondent should state its desire and willingness to allow and cooperate with the Companies in establishing real-time monitoring and metering of generation, including the installation of Companies' equipment at the Generating Facility site.

7. **Ancillary Services (Required Proposal Content)** – If a definitive agreement is entered into with a respondent, the Companies will require the unrestricted right, under such definitive agreement, to the capacity and energy associated with the Generating Facility that is the subject of such respondent's proposal, including all ancillary services capable of being produced by the Generating Facility. If applicable, a respondent's proposal should describe any ancillary services, including, but not limited to, load following, spinning reserve, supplemental reserve, black start capability, frequency response, etc., included in such proposal.

8. **Delivery (Required Proposal Content)** – The proposal shall state the required transmission paths to deliver capacity and energy from the Generating Facility to the Companies' transmission system. The capacity and energy must be deliverable to the Companies' transmission system. The respondent shall be and is responsible for all costs associated with the interconnection of the Generating Facility to the grid and the Companies will be responsible for the costs incurred moving the capacity and energy (including ancillary services) from the interconnection point to the Companies' transmission system and/or load.

9. **Environmental** – If a definitive agreement is entered into with a respondent, with respect to the sale of capacity and energy (including ancillary services) to the Companies under such definitive agreement, where permits are applicable for the product being sold, the respondent will be responsible for obtaining all necessary permits and complying with their requirements for the life of the agreement. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by respondent.

10. **Development Status (Required Proposal Content)** – Respondent shall provide a comprehensive narrative of the status of the development of any generation project intended to be used in a definitive agreement with the Companies. Respondent's narrative shall include the following:

    10.1. Comprehensive development and construction schedule (if applicable),
    10.2. Listing of all required permits and governmental approvals and their status,
    10.3. Listing of all required electric interconnection agreements and their status,
    10.4. Financing plan (if applicable), and
    10.5. Summary of key contracts (construction, major equipment, etc.), to the extent that they exist.

11. **Renewable Energy Certificates** – Any Renewable Energy Certificates ("REC") that are part of the proposal must be created from renewable facilities verified and approved by the proven renewable asset tracking systems associated with a major regional Independent System Operators ("ISO"). Applicable tracking systems are PJM's Generation Attribute Tracking System ("GATS") or MISO's Midwest Renewable Energy Tracking System ("MRETS"). The legal ownership of every REC so created is recorded and tracked by GATS or MRETS to assure its authenticity and single ownership.

12. **Financial Capability (Required Proposal Content)** – Should the Companies elect to enter into a definitive agreement with a respondent who later fails to meet its obligations under such definitive agreement at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, each respondent is required to demonstrate in its proposal, in a manner acceptable to the Companies, the respondent's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of a definitive agreement.

12.1. If a definitive agreement is entered into with a respondent, such respondent will be required to maintain, at all times during the term of such definitive agreement, an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

12.2. If a definitive agreement is entered into with a respondent, the respondent will, upon execution of such definitive agreement, be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the respondent. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. If the Companies draw down the LOC amount at any time, the seller must replace the LOC to the original value within five days.

13. **RFP Schedule** – All proposals, including all respective project data forms, must be complete in all material respects and be received no later than 4 P.M. EDT on August 17, 2022. All responses must be emailed to: Jun2022RFP@lge-ku.com.

RFP Issued	June 22, 2022
Proposals Due	August 17, 2022 at 4 P.M. EDT
Evaluation Completed	October 31, 2022

Proposals will not be viewed until 4 P.M. EDT on August 17, 2022. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that one or more proposals are in their customers' best interests. Any subsequent definitive agreement(s) will be contingent on obtaining the necessary regulatory approvals.

14. **Treatment of Proposals**

14.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in any proposal received. The Companies also reserve the right to modify this RFP or request further information, as necessary, to complete their evaluation of the proposals received.

14.2. Each respondent who submits a proposal does so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of capacity and/or energy (including ancillary services) for any reason. Each respondent is responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

15. **Confidentiality** – As regulated utilities, it is expected that the Companies will be required to release information contained in any proposal to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as

"Confidential." Please note that confidential treatment is generally more likely to be granted if limited amounts of information in a proposal, rather than large portions of the proposal, are designated as confidential. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to information contained in any proposal. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the respondent's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

16. **Contacts**

Chuck Schram, Director, Power Supply
LG&E and KU Energy LLC
Power Supply
220 West Main Street
Louisville, KY 40202

Phone: 502-627-3250

Linn Oelker, Manager, Market Compliance
LG&E and KU Energy LLC
Power Supply
220 West Main Street
Louisville, KY 40202

Phone: 502-627-3245

In closing, I look forward to your response by 4 P.M. EDT on August 17, 2022, and the possibility of doing business with you to meet the Companies' future power requirements.

Sincerely,

Chuck Schram

Chuck Schram
Director, Power Supply

LG&E and KU RFP Data Form		
PPA - Renewable Generation and/or Storage		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point.		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Start Date of PPA		mm/dd/yyyy
Term of PPA		years
Purchase Option Year (if applicable)		year
Nameplate Amount		MW
Annual Capacity Degradation		as a % of capacity per year
Summer Capacity Amount		MW
Summer Maximum Dispatch Capacity Amount (if applicable)		MW
Summer Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Summer On-Peak Capacity (2PM to 5PM EDT)		MW
Winter Capacity Amount		MW
Winter Maximum Dispatch Capacity Amount (if applicable)		MW
Winter Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Winter On-Peak Capacity (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp Capability:		
min ramp rate up (if applicable)		MW/minute
min ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		hours
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		minutes
Other cycling constraints (if applicable)		text
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Maximum number of annual curtailable hours		hours/year
Planned Outage Schedule		text
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Storage Resources (in addition to above)		
Technology		text
Battery Life (in years)		years
Battery Life (in cycles)		whole number
Economic Life		years
Storage Capacity		MW
Storage Capacity of Energy		MWh
Discharge Rate		MW/hour
Annual Storage Capacity Degradation		as a % of capacity/year
Maximum state of charge		%
Charge Rate		MW/hour
Minimum state of charge		%
Round trip charging losses		%
Maximum number of cycles allowed per day		whole number
Maximum number of cycles allowed per month		whole number
Maximum number of cycles allowed per week		whole number
Maximum number of cycles allowed per year		whole number
Maximum time battery can output at maximum generating capacity		hours
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with a PPA which may include but are not limited to:		
Fixed energy price over the term		$/MWh
Escalating energy price starting in year 1 of the term		$/MWh
Escalating energy price rate		% per year
Fixed capacity price		$/kW-month
Escalating capacity price starting in year 1 of the term		$/kW-month
Escalating capacity price rate		% per year
Purchase option price		$
END OF FORM	END OF FORM	END OF FORM

LG&E and KU RFP Data Form		
PPA - Fuel-Based Generation Resource		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point. Combined Cycle Units to state values for component combinations ((e.g., CT only, 1x1, 2x1, etc.)		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Interstate Pipeline interconnection location and Company		text
Description of pipeline between Interstate Pipeline and generation asset:		text
Start Date of PPA		mm/dd/yyyy
Term of PPA		years
Purchase Option Year (if applicable)		year
Nameplate Amount		MW
Summer Capacity Amount		MW
Summer Maximum Dispatch Capacity Amount (if applicable)		MW
Summer Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Summer On-Peak Capacity (2PM to 5PM EDT)		MW
Winter Capacity Amount		MW
Winter Maximum Dispatch Capacity Amount (if applicable)		MW
Winter Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Winter On-Peak Capacity (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp capability:		
ramp rate up (if applicable)		MW/minute
ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		minutes
Start fuel quantity (per start)		MMBtu per start
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		hours
Other cycling constraints (if applicable)		text
Emissions rate for NO_x		lbs per MMBtu
Emissions rate for SO_2		lbs per MMBtu
Emissions rate for CO_2		lbs per MMBtu
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Guaranteed Heat Rate		Btu/kWh
Mean time to repair		avg hours per outage event
Planned Outage requirements		days needed per year
Net heat rate curves (I/O coefficients preferred) – by month/season if applicable (By component combination for combined cycle units) provided electronically.		Y/N
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with a PPA which may include but are not limited to:		
Fixed energy price over the term		$/MWh
Escalating energy price starting in year 1 of the term		$/MWh
Escalating energy price rate		% per year
Start Cost		$ per start
Fixed capacity price		$/kW-month
Escalating capacity price starting in year 1 of the term		$/kW-month
Escalating capacity price rate		% per year
Purchase option price		$
END OF FORM	END OF FORM	END OF FORM

LG&E and KU RFP Data Form		
Sale Offer - Renewable Generation and/or Storage		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point.		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Sale Date		mm/dd/yyyy
Nameplate Amount		MW
Annual Capacity Degradation		as a % of capacity per year
Summer Capacity Amount		MW
Summer Maximum Dispatch Capacity Amount (if applicable)		MW
Summer Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Summer On-Peak Capacity (2PM to 5PM EDT)		MW
Winter Capacity Amount		MW
Winter Maximum Dispatch Capacity Amount (if applicable)		MW
Winter Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Winter On-Peak Capacity (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp capability:		
min ramp rate up (if applicable)		MW/minute
min ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		hours
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		minutes
Other cycling constraints (if applicable)		text
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Maximum number of annual curtailable hours		hours/year
Planned Outage Schedule		text
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Storage Resources (in addition to above)		
Technology		text
Battery Life (in years)		years
Battery Life (in cycles)		whole number
Economic Life		years
Storage Capacity		MW
Storage Capacity of Energy		MWh
Discharge Rate		MW/hour
Annual Storage Capacity Degradation		as a % of capacity/year
Maximum state of charge		%
Charge Rate		MW/hour
Minimum state of charge		%
Round trip charging losses		%
Maximum number of cycles allowed per day		whole number
Maximum number of cycles allowed per month		whole number
Maximum number of cycles allowed per week		whole number
Maximum number of cycles allowed per year		whole number
Maximum time battery can output at maximum generating capacity		hours
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with an asset sale which may include but are not limited to:		
Asset purchase price		$
Fixed O&M costs		$ per year
Variable O&M costs		$/MWh
Major maintenance costs		$ per event
Installation costs for Electric Transmission		$
Installation costs for Electric Interconnection		$
Other Installation costs		$
Other ongoing costs - Property taxes		$ / year
Other ongoing costs - Insurance		$ / year
Other ongoing costs - other		$ / year
END OF FORM	END OF FORM	END OF FORM

LG&E and KU RFP Data Form		
Sale Offer - Fuel-Based Generation Resource		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point. Combined Cycle Units to state values for component combinations ((e.g., CT only, 1x1, 2x1, etc.)		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Interstate Pipeline interconnection location and Company		text
Description of pipeline between Interstate Pipeline and generation asset:		text
Sale Date		mm/dd/yyyy
Nameplate Amount		MW
Summer Capacity Amount		MW
Summer Maximum Dispatch Capacity Amount (if applicable)		MW
Summer Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Summer On-Peak Capacity (2PM to 5PM EDT)		MW
Winter Capacity Amount		MW
Winter Maximum Dispatch Capacity Amount (if applicable)		MW
Winter Minimum Dispatch Capacity Amount (if applicable)		MW
Guaranteed Winter On-Peak Capacity (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp capability:		
min ramp rate up (if applicable)		MW/minute
min ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		hours
Start fuel quantity (per start)		MMBtu per start
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		minutes
Other cycling constraints (if applicable)		text
Emissions rate for NO_x		lbs per MMBtu
Emissions rate for SO_2		lbs per MMBtu
Emissions rate for CO_2		lbs per MMBtu
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Guaranteed Heat Rate		Btu/kWh
Mean time to repair		
Planned Outage requirements		days needed per year
Net heat rate curves (I/O coefficients preferred) - by month/season if applicable (By component combination for combined cycle units) provided electronically.	avg hours per outage event	Y/N
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with an asset sale which may include but are not limited to:		
Asset purchase price		$
Fixed O&M costs		$ per year
Variable O&M costs		$/MWh
Major maintenance costs		$ per event
Installation costs for Electric Transmission		$
Installation costs for Electric Interconnection		$
Installation costs for Gas Pipeline and gas interconnection		$
Other Installation costs		$
Other ongoing costs - Property taxes		$ / year
Other ongoing costs - Insurance		$ / year
Other ongoing costs - other		$ / year
END OF FORM	END OF FORM	END OF FORM

The entire attachment CRS-2 is Confidential and provided separately under seal.