a PPL company

SCC-CLERK'S OFFICE
DOCUMENT CONTROL CENTER

2017 MAY -1 A 9:43

170510004

Mr. Joel H. Peck, Clerk
Virginia State Corporation Commission
Document Control Center
1300 East Main Street
Tyler Building - First Floor
Richmond, Virginia 23219

Old Dominion Power Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lgee-ku.com

Rick E. Lovekamp
Manager - Regulatory Affairs/Tariffs
T 502-627-3780
F 502-627-3213
rick.lovekamp@lge-ku.com

VIA OVERNIGHT DELIVERY

April 28, 2017

**RE: Kentucky Utilities Company d/b/a Old Dominion Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.,
Case No. PUR-2017-00056**

Dear Mr. Peck:

Pursuant to the Virginia State Corporation Commission's ("Commission") December 19, 2016 Order in Case No. PUE-2016-00053, Kentucky Utilities Company, d/b/a Old Dominion Power Company ("KU/ODP"), please find enclosed and accept for filing its Integrated Resource Plan ("IRP"). The original and 15 copies of the IRP are enclosed with this letter. One copy of the IRP is being delivered to the Commission's General Counsel under separate cover. The original and each copy of the IRP contain the expurgated or redacted version of the information for which KU/ODP considers to be confidential and with the Motion for Protective Order KU/ODP requests be withheld from public disclosure.

In addition to the IRP, the Companies are filing a Motion for Protective Order requesting that the Commission establish procedures applicable to the use of confidential information in this proceeding. The original and 15 copies of the Motion for Protective Order are enclosed with this letter. One copy of the Motion for Protective Order is being delivered to the Commission's General Counsel under separate cover.

The information which KU/ODP through its Motion for Protective Order requests be withheld from public disclosure is enclosed with this letter. An original and 15 copies of the confidential information is enclosed in 15 separate opaque envelopes each marked "UNDER SEAL." On every document filed under seal, KU-ODP has marked each individual page of the document that contains confidential information, and on each such page has clearly indicated the specific information requested to be treated as confidential by use of highlighting marking. On additional copy of the confidential information is being delivered under seal in an opaque envelope to the Commission's General Counsel under separate cover.

Please confirm your receipt of this filing by placing the stamp of your Office with date received on the extra copy and returning to me in the enclosed envelope. Should you have any questions regarding this information, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

cc: William H. Chambliss, Commission General Counsel (Confidential Copy)
Delegate Terry G. Kilgore, Chairman, House Committee on Commerce and Labor (w/encl.)
Senator Frank Wagner, Chairman, Senate Committee on Commerce and Labor (w/encl.)
Senator Thomas K. Norment, Jr., Chairman, Commission on Electric Utility Regulation (w/encl.)
C. Meade Browder, Jr., Senior Assistant Attorney General, Office of the Attorney General (w/encl.)

Summary
170510004

ODP
2017 VA IRP SUMMARY

Kentucky Utilities Company ("KU") is, at its name implies, a Kentucky-based electric utility with limited operations in Virginia, in which it does business as Old Dominion Power Company ("ODP" or, the "Company"). In Kentucky, KU and its sister utility, Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), collectively serve over 900,000 customer accounts in over 80 of Kentucky's 120 counties with over 8,000 megawatts ("MW") of combined generating capacity, all of which is located in Kentucky and is subject to the jurisdiction of the Kentucky Public Service Commission ("Kentucky PSC"); neither KU nor LG&E (nor KU operating as ODP) owns or operates any generating assets in Virginia (indeed, LG&E has no utility assets or customers in Virginia). In contrast to LG&E and KU's significant Kentucky utility operations, ODP provides retail electric service to approximately 28,000 customers in the Virginia counties of Wise, Lee, Russell, Scott, and Dickenson, supplying those customers with energy from KU and LG&E's generating assets in Kentucky. The electric load in the ODP service territory in Virginia primarily consists of residential and coal mining operations. The territory is almost entirely rural and mountainous with negligible load growth and represents approximately five percent of KU's total customer base. KU and ODP's principal place of business is One Quality Street, Lexington, Kentucky 40507 and ODP maintains a Business Office in the town of Pennington Gap, Virginia and a Business Office and Operations Center in Norton, Virginia.

Recognizing the small scale of ODP's operations, the Virginia General Assembly exempted ODP from the requirements of the Virginia Electric Utility Regulation Act (VCA §§ 56-576 – 56-596). Nonetheless, ODP is subject to the recently amended requirements of VCA § 56-599 concerning the filing of integrated resource plans ("IRPs"). This filing is intended to satisfy the revised requirement of VCA § 56-599 that each electric utility file an updated IRP with the Virginia State Corporation Commission ("Commission") by May 1.

ODP
2017 VA IRP SUMMARY

In Kentucky, LG&E and KU are regulated utilities and are subject to triennial IRP filing requirements. Since LG&E and KU came under common control in 1998, they have filed joint IRPs in Kentucky in 2002, 2005, 2008, 2011, and 2014. In November 2018, LG&E and KU will their next IRP filing with the Kentucky PSC. LG&E and KU file joint IRPs because they jointly plan and operate their generating and transmission resources, including jointly dispatching their generating units and establishing a common reserve margin for planning, reporting, and operating the joint system. This joint planning and operation allows for potential cost savings, deferral of capacity expenditures, and more efficient use of generating and transmission capacity, all of which benefit customers in the Kentucky and Virginia service territories. Additionally, beginning in 2011, ODP has filed IRPs as required under the Code of Virginia.

Through the resource planning process, LG&E and KU maintain an ongoing commitment to identify and meet customers' future energy needs in the most reliable and economical manner using robust economic and forecasting methodologies. Additional resource planning variables taken into consideration when modeling and developing the IRP include future capacity needs, fuel and energy costs, renewable energy resource options, fuel diversity, technology deployment, and dynamic and evolving environmental regulations. Concerning the latter variable, for example, since the U.S. Environmental Protection Agency issued its final Clean Power Plan in November 2015, uncertainty has existed as to what future carbon-dioxide-emission-reduction requirements will be mandated and implemented by each state.

ODP regularly provides the Commission with ample information to ensure ODP is serving its customers safely, reliably, and economically. For example, each February, ODP files with the Commission an application, testimony, and supporting schedules to recover its forecasted fuel costs through the levelized fuel factor ("LFF"). The fuel costs are adjusted to reflect any over-recovery or under-recovery of fuel costs previously incurred. ODP provides the Commission with exhibits of projected fuel expenses and sources at the point of delivery at the transmission level, projected Virginia jurisdictional kWh sales and fuel expense recovery assuming the LFF remains unchanged, a calculation of the proposed LFF, and an ODP service territory map. Also, forecasted and actual data is provided for fuel expense, generation output, equivalent availability, capacity factors, heat rates, equivalent forced outage rates, dependable capacity ratings, average dispatch cost by generating unit, fuel consumption, heat content in MBtu, average heat content of the primary fuel, and fuel expense in cents per MBtu by generating unit.

Also, LG&E and KU file in Kentucky an Annual Resource Assessment each April, much of which ODP then files annually with the Commission in narrative summaries. The assessment includes annual weather-normalized energy sales, monthly power purchases, actual and weather-normalized monthly coincident peak demands, load shape curves of actual and weather-normalized peak demands, load shape curves showing the number of hours that native load demand exceeded these levels, target and projected reserve margins, forced outages greater than two hours in duration, current and planned scheduled outages or retirements of generating capacity, planned base load or peaking capacity additions to meet native load, transmission energy data, and all planned capacity additions. Therefore, ODP provides the Commission with a significant amount of operational information on an annual basis, which provides the Commission a clear view of LG&E and KU's operations and planning, enabling the Commission to ensure that ODP will be able to continue to provide safe, reliable, and economical service to its Virginia customers.

Finally, it is noteworthy that because KU and LG&E's Kentucky-based generating assets serve ODP's customers in Virginia, the emissions from those generating assets do not and will not affect Virginia's ability to comply with the potential federal Clean Power Plan if enacted.

ODP places a strong emphasis on energy conservation through consumer education, employing several methods to disseminate energy efficiency and conservation tips. First, the Company prepares the Power Source newsletter, which customers receive with their monthly bills. Power Source provides ODP customers with proactive and practical energy conservation tips and educational material. Second, the Company's website provides seasonal and year-round information on low-cost and no-cost ways for customers to reduce energy usage, including tips related to lighting, heating and cooling, appliances and electronics, insulation and air sealing, and water usage. Third, the Company provides materials containing energy-efficiency tips at various public gatherings and community festivals.

KU and LG&E have a robust portfolio of successful and cost-effective demand-side-management and energy-efficiency ("DSM-EE") programs that provide benefits to ODP's customers in Virginia. KU and LG&E's DSM-EE programs will provide a cumulative demand reduction of up to 500 MW and cumulative energy savings of 1.1 million MWh by 2018. Because ODP's Virginia customers receive their energy from KU and LG&E's generating resources in Kentucky—ODP, KU, and LG&E do not own generating resources in Virginia—these demand and energy reductions in Kentucky provide benefits to ODP's Virginia customers in the form of avoided capacity costs and relatively lower energy costs. Also, because KU and LG&E's Kentucky-based generating assets serve ODP's customers in Virginia, the emissions from those generating assets will not impede Virginia's ability to comply with the potential federal Clean

Power Plan if enacted, regardless of the amount of energy efficiency ODP's customers are able to achieve.

Providing ODP's customers with safe and reliable electric service at low rates requires continuous investment in generation, transmission, and distribution facilities. ODP's generation facilities are located in Kentucky and largely burn coal or natural gas to generate electricity. The coal and natural gas are procured through competitive bid practices from domestic suppliers. Due to increasingly stringent environmental regulations applicable to such coal-fired generation, the Companies continue to engage in the most significant environmental-compliance construction program in their history. ODP is largely exempt from the Virginia Electric Utility Restructuring Act. As a result, ODP's cost recovery is limited to a levelized fuel factor and traditional base rate cases. The Utility Restructuring Act's various rate-adjustment riders are not available to ODP. Under these circumstances and with these limitations, ODP currently expects to file traditional base rate cases every two years to recover the cost of these investments.

Notwithstanding the Companies' investment in new gas-fired generation facilities, environmental controls at existing coal-fired generation facilities, a new 10 MW solar photovoltaic facility, and approval to develop a 4 MW solar share facility in 500 kW phases, ODP's rates have historically been lower than those of any other investor-owned utilities. With the exception of the coal mining industry, ODP's southwestern-Virginia service territory does not have large, energy-intensive industries. Electric sales to the coal mining industry are declining as this industry consolidates and retracts.

ODP regularly meets with state and local stakeholders to support economic development in its service territory, is committed to investing in Virginia to reliably serve its Virginia customers, and continues to maintain two business offices and over 30 employees in Virginia to serve Virginia customers.

Additional information is available in the Exhibits noted below.

- Exhibit 1 – Clean Power Plan Status
- Exhibit 2 – Environmental Regulations
- Exhibit 3 – 2017 Resource Assessment (portions considered confidential)
- Exhibit 4 – Schedules 1 – 18 (portions considered confidential)

This IRP represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

170510004

Exhibit 1

EXHIBIT 1

Clean Power Plan Status – ODP

The VSCC stated in its Final Order concerning KU/ODP's 2016 IRP:

> The CPP is currently stayed by the Supreme Court of the United States. Even if the CPP is upheld, it could be several years before a final SIP is approved in either Virginia or Kentucky. Until such time, an IRP can only present scenarios that are based on compliance assumptions, rather than the specific requirements of compliance.
>
> Accordingly, we find that KU/ODP should include in its next IRP filing with the Commission an update regarding the Company's plans and Kentucky's plans to comply with the CPP. This should include: (i) an assessment of the Company's ability to comply with Section 111(d) under a rate-based approach; (ii) an assessment of KU/ODP's ability to comply with Section 111(d) under a mass-based approach; (iii) an assessment of the rate impacts of the final Section 111(d); and (iv) an update on the status of Kentucky's development of a SIP.[1]

Kentucky has consistently opposed the Clean Power Plan ("CPP"). Following the U.S. Environmental Protection Agency's ("EPA") June 2014 publication of its proposed CPP, Kentucky joined 11 other states in a lawsuit opposing the CPP.[2] In addition, in late 2014 the Kentucky Attorney General filed comments with the EPA opposing the rulemaking,[3] and the Kentucky Energy and Environment Cabinet filed comments expressing serious concerns about the proposed rule.[4] On August 5, 2015, Kentucky joined 15 other states in petitioning the EPA for an administrative stay of the final CPP, which EPA had issued, but not published in the Federal Register, on August 3, 2015.[5] The EPA did not grant the stay and published the final CPP in the Federal Register on October 23, 2015.[6] The same day, Kentucky joined 23 other states in filing an action in the U.S. Court of Appeals for the District of Columbia Circuit to hold unlawful and set aside the rule,[7] and to petition the court for a stay of the CPP during the appeal.[8]

Therefore, it was only over Kentucky's consistent opposition that the final CPP was published in the Federal Register in October 2015. The final Clean Power Plan contains state-specific rate-based and mass-based reduction goals and guidelines for the development,

---

[1] *In re: Kentucky Utilities Company d/b/a Old Dominion Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, VSCC Case No. PUE-2016-00053, Final Order at 6 (Dec. 19, 2016).
[2] *West Virginia, Commonwealth of Kentucky et al. v. U.S. EPA*, No. 14-1146 (D.C. Cir. 2014); *see also In Re: Murray Energy Corp.*, Case No. 14-1112, *consolidated with* 14-1151 (D.C. Cir. 2014).
[3] *Available at* http://www.ieca-us.com/wp-content/uploads/Comments-of-Kentucky-Attorney-General-Jack-Conway_12.01.141.pdf.
[4] *Available at* http://www.ieca-us.com/wp-content/uploads/KY-Energy-and-Environment-Cabinet-Comments_11.26.14.pdf.
[5] *See* http://www.ieca-us.com/wp-content/uploads/16-States-Ask-for-CPP-Hold_08.05.15.pdf.
[6] 80 Fed. Reg. 64,661 *et seq.* (Oct. 23, 2015).
[7] *Available at* http://www.ago.wv.gov/pressroom/2015/Documents/File-stamped%20petition%2015-1363%20(M0108546xCECC6)-c1.pdf.
[8] *Available at* http://www.ieca-us.com/wp-content/uploads/States-Motion-for-Stay_10.23.15.pdf.

EXHIBIT 1 17051004

submission and implementation of state implementation plans to achieve the state goals. State-specific goals were calculated from 2012 data by applying EPA's broad interpretation and definition of the Best System of Emissions Reduction, resulting in the most stringent targets to be met in 2030, with interim targets to be met beginning in 2022. The final CPP gives states the option to use a rate-based approach (limit emissions per megawatt hour) or a mass-based approach (limit total tons of emissions per year), and the option to demonstrate compliance through emissions trading and multi-state collaborations. Under the rate-based approach, Kentucky would need to make a 41% reduction from its 2012 emissions rate and under a mass-based approach it would need to make a 36% reduction. These reductions are significantly greater than initially proposed and present significant challenges to the state.

Indeed, because the final emission restrictions for Kentucky are so much more stringent than those EPA initially proposed, in December 2015 Kentucky filed a petition for reconsideration with the EPA, noting, "Many of these changes are so dramatic and unanticipated that it would have been 'impracticable,' if not impossible, for the Commonwealth to raise objections about these changes during the public comment period."[9] Kentucky's petition further stated that, because the EPA did not conduct state-by-state cost-benefit analyses to determine the impact of its final rule on the economy of each state, "[T]he targets for Kentucky have a devastating effect on ratepayers, the economy, and the standard of living in the Commonwealth and other similarly situated states."[10] On January 11, 2017, the EPA denied Kentucky's petition.[11]

At this time, Kentucky has not formulated a state plan to comply with the final CPP or committed to formulate such a plan instead of accepting a federal compliance plan. But it currently appears unlikely Kentucky would opt for a federal plan: On January 21, 2016, Kentucky filed comments critical of the proposed federal plan, concluding that the proposed plan "does not provide for the meaningful participation required for rulemaking, it improperly expands statutory authority, increases regulatory uncertainty, and is based upon uncertain and limited analysis."[12] The comments further asked the EPA to withdraw the proposed federal plan.[13]

The same day, Kentucky announced it would be seeking a two-year extension of the deadline to file a state compliance plan.[14] The announcement stated the purpose of seeking the extension was to "allow Kentucky to consider its options and continue its fight against this plan that will harm Kentucky's affordable, reliable electricity and devastate the economy statewide," and "to allow serious legal challenges to progress through the court." The announcement further stated that Kentucky's Energy and Environment Cabinet would conduct public listening sessions across the Commonwealth to gather input concerning how to proceed concerning the CPP.

---

[9] *Available at* http://eec.ky.gov/Documents/December%2021%20Petition%20for%20Reconsideration%20of%20111(d).pdf.
[10] *Id.*
[11] *Available at* https://www.gpo.gov/fdsys/pkg/FR-2017-01-17/pdf/2017-00941.pdf.
[12] *Available at* http://air.ky.gov/SiteCollectionDocuments/GreenhouseGasEmissions_FederalPlanRequirements_Comments.pdf.
[13] *Id.*
[14] *Available at* http://energy.ky.gov/Documents/EEC_CPP_Extension_FINAL.pdf.

A few days later, Kentucky did indeed continue its fight against the CPP. Following the January 21, 2016 refusal of the U.S. Court of Appeals for the District of Columbia Circuit to stay the CPP, Kentucky joined 28 other states on January 26, 2016, in seeking a stay from the U.S. Supreme Court.[15] Shortly thereafter on February 9, 2016, the U.S. Supreme Court issued an order staying the CPP pending all appellate review of the CPP, including any review by the Court.[16]

The next day, Kentucky issued an announcement applauding the stay and deferring any listening sessions proposed in its January 21 announcement: "Conducting listening sessions at this time is premature because the CPP could change substantially as a result of litigation, or it could be vacated altogether."[17] Therefore, Kentucky appears to have suspended its work concerning potential CPP compliance plans.

Kentucky's apparent suspension of work on CPP compliance is consistent with the advice later given by the senior U.S. Senator from Kentucky, Sen. Mitch McConnell, who on March 21, 2016, sent a letter to the National Governors Association recommending that states continue to take a wait-and-see approach to the CPP rather than moving forward with compliance efforts.[18] Notably, Sen. McConnell took the view that the stay granted by the U.S. Supreme Court will cause the deadlines and target dates stated in the final CPP to adjust forward to account for the duration of the stay if the CPP survives all appeals.[19]

In September 2016, the D.C. Circuit heard oral arguments regarding the CPP, but has not yet issued a decision. And on March 28, 2017, President Donald Trump signed the "Presidential Executive Order on Promoting Energy Independence and Economic Growth" which in part requires the Administrator of the EPA to review and, if appropriate, revise or withdraw the CPP.[20] Hours later, President Trump's Administration requested that the D.C. Circuit postpone ruling on the CPP until after the EPA Administrator completes review of the CPP.[21] Scott Pruitt is the EPA's Administrator, having been confirmed by the Senate on February 17, 2017.[22] These recent actions have added to the uncertainty concerning the CPP. In its Final Order concerning KU/ODP's 2016 IRP, the VSCC anticipated that the "upcoming change in federal administrations may add some degree of uncertainty as to future implementation [of the CPP.]"[23]

---

[15] *See* http://www.ago.wv.gov/publicresources/epa/Documents/Final%20States%20SCOTUS%20Stay%20App%20-%20ACTUAL%20%28M0116774xCECC6%29.pdf.
[16] *West Virginia v. Environmental Protection Agency*, No. 15-1363 (D.C. Cir.), *stay granted* (U.S. Feb. 9, 2016) (No. 15A776).
[17] *Available at* http://eec.ky.gov/Lists/News%20Releases%202/Energy%20and%20Environment%20Cabinet%20defers%20listening%20sessions%20after%20Supreme%20Court%20decision.pdf.
[18] *Available at* http://www.mcconnell.senate.gov/public/?a=Files.Serve&File_id=6AB51ED1-3638-4442-85B0-3C56D721861B
[19] *Id.* at 1-2.
[20] *Available at* https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1.
[21] *Available at* http://bigstory.ap.org/89ac37ed2e2b40fd8af3cf02e04c152f.
[22] *Available at* https://www.epa.gov/aboutepa/epas-administrator.
[23] Case No. PUE-2016-00053, Final Order at 6 (Dec. 21, 2016).

If the CPP survives the current litigation or the EPA ultimately issues a new and similar rule, Kentucky's ability to comply with it will be complicated by legislation passed by the Kentucky General Assembly in April 2014 that limits the measures that the Kentucky Energy and Environment Cabinet may consider in setting performance standards to comply with the EPA's regulations governing greenhouse gas ("GHG") emissions from existing sources. The legislation, now codified as KRS 224.20-140 *et seq.*, provides that such state GHG performance standards shall be based on emission reductions, efficiency measures, and other improvements available at each power plant, rather than renewable energy, end-use energy efficiency, fuel switching and re-dispatch. These statutory restrictions may make it more difficult for Kentucky to achieve any significant GHG reductions required by the CPP or a successor rule.

In light of the U.S. Supreme Court's stay and Kentucky's current position on formulating a CPP compliance plan, there is considerable uncertainty surrounding what the CPP will ultimately require of KU and its sister utility, Louisville Gas and Electric Company ("LG&E"). But it seems likely some changes will have to be made if the CPP survives in its current form. Concerning a rate-based compliance approach, LG&E-KU's combined CO_2 emission rate in 2012 was 2,112 lbs/MWh, which was slightly below the Kentucky state average of 2,166 lbs/MWh. But the final CPP's 2030 rate-based target for Kentucky is 1,286 lbs/MWh, 41% less than Kentucky's actual 2012 emission rate. En route to the 2030 target, though, are several less stringent interim average targets: 1,643 lbs/MWh for 2022-24; 1,476 lbs/MWh for 2025-27; and 1,358 lbs/MWh for 2028-29. To comply on a rate-based approach, LG&E and KU may need to modify their current portfolio of generating assets during the next decade, participate in an allowance trading program, or both. It appears likely that other market-based mechanisms such as a single- or multi-state Emission Reduction Credit (ERC) purchase mechanism may be available for consideration by Kentucky. The precise timing and amount of such changes is unknown, and cannot be known with any reasonable certainty until the compliance plan applicable to Kentucky, and therefore to KU and LG&E, is known. Similarly, the rate impacts of CPP compliance cannot be projected with any accuracy at this time, though eventual rate increases resulting from CPP compliance appear highly likely.

A mass-based approach, which Kentucky's Energy and Environment Cabinet currently appears to favor, would require Kentucky to reduce its CO_2 emissions from its 2012 level of 91.4 million tons per year ("TPY") to 63.1 million TPY in 2030, with interim targets of 76.8 million TPY in 2022-24, 69.7 million TPY in 2025-27, and 65.7 million TPY in 2028-29. Based on the Kentucky's Energy and Environment Cabinet's projections of CO_2 emissions from electric generation, which show Kentucky's emissions have been decreasing consistently since 2010, it appears Kentucky may not have to make any major changes to meet a mass-based approach for the first interim target period, i.e., though the end of 2024. Beginning in 2025, though, reductions from projected levels would be necessary. If Kentucky ultimately falls under a mass-based compliance approach, particularly with a single- or multi-state allowance-trading mechanism, it is possible KU may not have to change its current generating fleet significantly to achieve CPP compliance. But as with a rate-based approach, it appears highly likely CPP compliance would result in higher rates for customers due to allowance purchases, capacity changes, or a combination of the two. What those increased costs, and therefore increased rates, might be is unknown at this time, and cannot be known until the compliance plan applicable to Kentucky, and therefore to KU and LG&E, is known.

170510004

Exhibit 2

EXHIBIT 2 170510004

VA IRP ENVIRONMENTAL REGULATIONS

All environmental considerations applicable to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively, the "Companies") electrical generation are addressed with applicable local, Kentucky, Virginia and Federal regulatory agencies. Although the Companies do not operate and maintain electrical generating facilities in the Commonwealth of Virginia, descriptions of environmental regulations that affect the Companies' electrical generating facilities are provided in this section.

Clean Water Act - 316(b) - Regulation of cooling water intake structures

In May 2014, the U.S. Environmental Protection Agency ("EPA") issued a revised 316(b) regulation. The Companies expect industry and environmental groups will use the court system to challenge the regulation and possibly delay its implementation deadlines. The regulation addresses impingement and entrainment impacts for aquatic species, thus possibly affecting all the Companies' intake water facilities. Data is currently being collected and will be submitted to the appropriate Kentucky agency during the Companies' National Pollution Discharge Elimination System ("NPDES") permit renewal process.

Clean Water Act – Effluent Limitation Guidelines ("ELG")

Draft regulations were proposed by EPA in May 2013 with final promulgation due in May 2014, but EPA sought and was granted an extension. On November 3, 2015 EPA published the final ELG regulations in the Federal Register. The revised regulations will require major changes to wastewater treatment systems at existing coal-fired plants, especially facilities with wet scrubbers. New discharge limits will be incorporated into each facility's NPDES water discharge permit between 2018-2023. On April 13, 2017, the EPA announced that it will reconsider the ELG regulations and that it intends to stay the rule's upcoming deadlines, pending further review. However, because this review is not likely to impact Kentucky's state water quality standards, the review is not expected to materially affect the Companies' future plans for wastewater compliance.

Acid Rain Program

The Acid Deposition Control Program was established under Title IV of the Clean Air Act as Amended ("CAAA") and applies to the acid deposition that occurs when sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X") are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog, or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in SO_2 emissions and NO_X emissions from the 1980 levels in the 48 contiguous states.

Phase II of the CAAA's Acid Deposition Control Program established a cap on annual SO_2 emissions of approximately 8.9 million tons by the year 2000. The legislation obtained these SO_2 emission reductions from electric utility plants of more than 25 MW (known as "affected units") through the use of a market-based system of emission allowances. Once allocated, allowances may be used by affected units to cover SO_2 emissions, banked for future use, or sold to others. All of the Companies' generating stations operate within these SO_2 compliance obligations.

The Acid Deposition Control Program of NO_X under the CAAA is not an allowance-based program, but instead established annual NO_X emission limitations based on boiler type to achieve emission reductions. NO_X emission reduction controls must be in place when the affected unit is required to meet the NO_X standard. The maximum allowable NO_X emission rates for Phase I are 0.45 lb NO_X /MMBtu for tangentially fired boilers and 0.50 lb NO_X /MMBtu for dry-bottom, wall-fired boilers. For Phase II, the maximum allowable NO_X emission rates are 0.40 lb NO_X /MMBtu for tangentially fired boilers and 0.46 lb NO_X /MMBtu for dry-bottom, wall-fired boilers.

All of KU's affected units complied with the Phase II NO_x reduction requirements through a system-wide NO_x emissions averaging plan (average Btu-weighted annual emission limit). Compliance was achieved through the installation of advanced low NO_x burners on Ghent Units 2, 3 and 4.

All of LG&E's affected units complied with the Phase II NO_x reduction requirements on a "stand-alone" or unit-by-unit NO_x emission limitation basis. All of LG&E's units took advantage of the "early election" compliance option under the NO_x reduction program. EPA allowed "early election" units to use the Phase I NO_x limits, thus avoiding the more stringent Phase II NO_x limits. All of the Companies' generating stations operate below their NO_x compliance obligations.

NOx SIP Call

The NO_x State Implementation Plan ("SIP") Call was promulgated under Title I of the CAAA of 1990 to control the formation and migration of ozone resulting from the presence of NO_x in the atmosphere. Title I requires all areas of the country to achieve compliance with the National Ambient Air Quality Standards ("NAAQS") for ozone, or ground-level smog. In September 1998, EPA finalized regulations (known as the "NO_x SIP Call") to address the regional transport of NO_x and its contribution to ozone non-attainment in downwind areas. EPA maintained that NO_x emissions from the identified states "contribute significantly" to non-attainment in downwind states and that the SIPs in these states were therefore inadequate and had to be revised. EPA's NO_x SIP Call required 19 eastern states (including Kentucky) and the District of Columbia to revise their SIPs to achieve additional NO_x emissions reductions that EPA believed necessary to mitigate the transport of ozone across the Eastern half of the United States and to assist downwind states in achieving compliance with the ozone standard. The final rule required electric utilities in the 19-state area to retrofit their generating units with NO_x control devices by the ozone season of 2004.

The Companies developed a NO_x SIP Call compliance plan (as outlined in Kentucky PSC Case Nos. 2000-386 and 2000-439), which resulted in compliance with the NO_x reduction requirements at the lowest combined capital and operating-and-maintenance life-cycle costs across the Companies' generation fleet. The plan implemented NO_x emission reduction technologies on a lowest "$/ton" of NO_x removed basis, to provide flexibility should regulatory or judicial changes affect the level or the timing of the NO_x reduction required.

In fulfillment of the NO_x SIP Call compliance plan, NO_x emissions from the Companies' coal-fired generating units were reduced through the installation of selective catalytic reduction ("SCR") on six of the Companies' generating units. Additional NO_x control technologies (including advanced low-NO_x burners and overfire air systems) were also installed on nearly every generating unit in the system to reduce the NO_x formed in the combustion zone of the boiler. Additionally, neural network software was installed on many of the generating units to enable better control of the boiler combustion process.

Clean Air Interstate Rule / Cross-State Air Pollution Rule

On March 15, 2005, EPA issued the Clean Air Interstate Rule ("CAIR"), which required significant reductions in SO_2 and NO_x emissions in an attempt to bring a number of states and regions into compliance with the NAAQS for $PM_{2.5}$ and eight-hour ozone (smog). But a number of states and other interveners challenged CAIR in court on several grounds, and on July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and remanded it to EPA for re-promulgation in a form consistent with the court's opinion.[1] The court placed CAIR back into effect several months later; however, the court's later order still required EPA to promulgate a regulation to replace CAIR.[2] Because the rule was remanded without vacatur, the CAIR NOx reduction program began in 2009 and the SO_2 program began in 2010 and included a Phase II beginning in 2015 to further reduce NOx and SO_2 allowances and associated emissions that can be transported across state lines.

The originally proposed effort by EPA to replace CAIR was referred to as the Clean Air Transport Rule ("CATR"), and was later renamed the Cross-State Air Pollution Rule ("CSAPR"). On August 6, 2011, the EPA published in the federal register the final version of CSAPR. CSAPR included limitations on interstate trading and prescribed a new trading program for SO_2 allowances that did not allow for previously banked allowances to be used in this new program. The reductions prescribed by CSAPR were similar to the Companies' CAIR reductions. CSAPR included a two-phase program for both NOx and SO_2, with less reduction of NOx required by the Companies by 2012 and somewhat less reduction required for 2014 and beyond. The reduction under CSAPR for SO_2 compared with the reduction under CAIR would be somewhat less in 2012 and somewhat more in 2014 and beyond.

Due to subsequent petitions against the CSAPR, primarily concerning issues with EPA methodology of allocations for alleviating states' contributions to downwind ozone and $PM_{2.5}$ issues, CSAPR was stayed by the D.C. Circuit court in December 2011. On August 12, 2012, the D.C. Court of Appeals vacated CSAPR, remanded it to EPA for rewriting, and ordered EPA to

---

[1] *North Carolina v. EPA*, 531 F. 3d 896 (D.C. Cir. 2008).

[2] *North Carolina v. EPA*, 550 F. 3d 1176, 1178 (D.C. Cir. 2008) ("We therefore remand these cases to EPA without vacatur of CAIR so that EPA may remedy CAIR's flaws in accordance with our July 11, 2008 opinion in this case.").

continue to administer CAIR until EPA completed and promulgated necessary revisions to CSAPR.

The EPA and a number of environmental groups, states, and others petitioned the D.C. Circuit Court of Appeals for a full court re-hearing of CSAPR. The petition was denied on August 12, 2012. A similar appeal was then filed with the Supreme Court. In June 2013, the Supreme Court agreed to rehear arguments to re-instate CSAPR. The initial arguments were heard in December 2013. CAIR continued to be implemented until a decision by the Supreme Court in April 2014 reversed the D.C. Circuit ruling overturning CSAPR and remanded the case to the lower court. The D.C. Circuit subsequently granted EPA's motion to lift the stay of CSAPR. As a result, EPA reinstated CSAPR with Phase 1 beginning January 1, 2015, and Phase 2 beginning January 1, 2017. Allocations for the Companies' system for Phase 1 of CSAPR were of similar quantity as those from CAIR.

Due to continuing ozone non-attainment issues primarily in the northeast, EPA determined through preliminary modeling that emissions from Kentucky and 8 other states are significantly contributing to downwind ozone attainment issues. On September 7, 2016, the EPA finalized the CSAPR Update Rule ("CSAPR II") to further reduce ozone season NO_X 30% compared to the reduced 2017 allocations of the original CSAPR allocations beginning in 2017. Additionally, the number of banked allowances at the end of 2016 were reduced such that only about 30% could be carried forward for use in 2017 and beyond. The Companies are assessing operational and capital impacts with respect to long term impacts of the CSAPR Update Rule.

Clean Air Visibility Rule

In April 1999, EPA issued final regulations known as the Clean Air Visibility Rule ("CAVR"), formerly known as the Regional Haze Rule, to protect 156 pristine (Class I) areas of the U.S., which are primarily national parks and wilderness areas. The goal of the regulatory program is to achieve natural background levels of visibility, that is, visibility unimpaired by manmade air pollutants in Class I areas, by 2064. Kentucky has one designated Class I area, Mammoth Cave National Park, and is required to assess visibility impacts to this area.

CAVR gives states flexibility in determining reasonable progress goals for the areas of concern, taking into account the statutory requirements of the CAAA. The final regulation requires all 50 states to reduce emissions of fine particulate matter and other air pollutants, including SO_2 and NO_X, and any other pollutant that can, via airborne transport, travel hundreds of miles and affect visibility in Class I areas. Incremental improvements of visibility in the affected areas are required to be seen early in the next decade.

In June 2001, the EPA proposed guidelines on what constituted Best Available Retrofit Technology ("BART") for the reduction of regional haze issues. The BART requirement applies to all facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year ("tpy") of visibility-impairing pollution. The guidelines are to be used by the states to determine how to set air pollution limits for facilities in 26 source categories, including power plants. EPA's guidance was remanded back to the agency by the D.C. Circuit to eliminate from the source categories those emission points whose contribution to visibility impairment is negligible. On May 5, 2004, new step-by-step guidance was published for states to implement the rule. The guidance additionally included a determination that emissions of SO_2 and NO_X should not be included in modeling the impact of coal-fired generating units in compliance with the CAIR rule, otherwise referred to as "CAIR equals BART". The emissions from the Companies' affected units were evaluated for their potential visibility impact on affected Class I areas. From that data, Mill Creek Units 1-4 were the only units identified as having a significant visibility impact.

Following an engineering analysis, it was determined that current plans for control technology installations of dry sorbent injection systems would meet the requirements for BART. This data along with all other affected facilities information was submitted to the Kentucky Division for Air Quality ("KDAQ"). The Companies submitted a CAVR SIP in December 2007 to EPA and the National Park Service. Subsequently, KDAQ submitted a revision to the SIP on May 27, 2010. On March 30, 2012, EPA published a limited approval and limited disapproval of the SIP revision. The limited disapproval was due to the SIP's reliance on CAIR (which was remanded after the SIP had been submitted) for meeting regional haze requirements. On May 30, 2012, EPA finalized replacement of reliance on CAIR with reliance on CSAPR in state's SIP. However, there is ongoing litigation for this "CSAPR equals BART" issue.

Additionally, CAVR contains review time periods in which an evaluation is made on how well progress is being made to meet the 2064 goal. Within the review period (15 years) of this report, a review of the progress will be made in 2018 that will include the additional reduction of fine particulate matter and SO_2 emissions associated with the Mercury and Air Toxics Standards ("MATS") Rule and shutdown of coal-fired units in the region. Depending on that analysis, further steps may be taken by regulators to ensure the 2064 goal can be met.

Following remand of the CAIR rule, EPA determined that for those Electric Generating Units ("EGUs") located in states subject to CSAPR, compliance with the SO_2 and NO_X reductions required under CSAPR would represent compliance with the SO_2 and NO_X requirements under BART. Thus, for those CSAPR regulated states, CSAPR compliance equals BART compliance. EPA has since also issued an opinion memorandum that CAIR regulated states can consider units in compliance with CAIR as also in compliance with BART. In addition, KDAQ has stated their agreement that CAIR compliance is equal to BART compliance. With the Supreme Court ruling that re-instated CSAPR, EPA has issued associated discussion that CSAPR transport emissions reduction program can be used demonstration of compliance with the BART visibility regulations (i.e., "CSAPR = BART"). However, there is on-going litigation of the "CSAPR equals BART" issue.

Hazardous Air Pollutant Regulations

The EPA has developed final rules to establish National Emission Standards for Hazardous Air Pollutants for the coal- and oil-fired electric utility industry. The Mercury and Air Toxics Standards ("MATS") rule was published in the Federal Register on February 16, 2012, and set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the maximum achievable control technology ("MACT") for the industry. The emission standards within this rule have instigated multiple installations of pulse jet fabric filters for additional control of particulate matter containing trace amounts of certain toxic metals and the shutdown of older coal-fired generation, some of which is to be replaced with new natural gas combined cycle generation. The compliance date was April 16, 2015; however, the rule allowed the permitting authority to grant up to a one year extension based on submittal of a justifiable request.

To meet emissions compliance limitations with the MATS rule, the Companies have completed the process of installing pulse jet fabric filter systems ("PJFF") with systems to inject powdered activated carbon ("PAC") on all coal-fired units with the exception of Trimble County Unit 2 and E.W. Brown Units 1 and 2. The Trimble County Unit 2 currently includes a PJFF with PAC injection as original equipment and E.W. Brown Units 1 and 2 is utilizing additives to assist with mercury removal and combine their emissions with the emissions of E.W. Brown Unit 3. Dry sorbent injection systems have been installed on each unit that received a PJFF system for the purpose of protecting the materials of construction. PAC injection systems have been added to enhance removal of mercury emissions. Emissions of mercury and acid gases are further reduced at all coal-fired units with the existing wet flue gas desulfurization ("WFGD") systems and with new WFGD systems at Mill Creek Units 1 through 4. Additionally, additives to WFGD systems to keep mercury from being re-entrained have been installed at some locations within the Companies' system. The use of these additives allows operations to optimize cost and performance of mercury control with PAC and/or WFGD additives.

National Ambient Air Quality Standards

SO_2

The EPA set the implementation process and timeline relative to the one-hour standard published as a final rule in June 2010. The 2010 NAAQS for SO_2 is a 1-hour primary (i.e., health based) SO_2 standard of 75 parts per billion ("ppb"), based on the three year average of the fourth highest of the 1-hour maximum concentrations. Kentucky made their initial SO_2 attainment recommendations in January 2013 for areas with adequate monitoring and the initial non-attainment designations approved by EPA were published in the Federal Register in October 2013. The historical 3-hour ambient monitoring SO_2 data (2009 – 2011) at the Watson Lane monitor location in Jefferson County was utilized by the state and local air agencies to designate the area adjacent to the Mill Creek Generating Station in non-attainment of the new standard. The Louisville Metro Air Pollution Control District ("LMAPCD") and Kentucky must submit a SIP that contains enforceable emission limitations or control measures on sources contributing to non-attainment in order to achieve attainment by October 2018. The KDAQ has not completed the SIP revision to date but had indicated that air dispersion modeling performed in support of that effort had shown that compliance with the MATS rule will resolve culpability issues at the Mill Creek

Station. In April 2015, KDAQ notified sources that were deemed from a combination of emissions and surrounding to have further need of evaluation of attainment status by either installation of a nearby monitoring system or through an approved modeling effort. The Companies' sources did not receive the notification of need for additional evaluation. However, the Companies have worked with LMAPCD on a plan to bring the area adjacent to the Mill Creek Generating Station in Jefferson County into attainment by accepting an SO_2 limit that is consistent with the SO_2 limits of the MATS rule; but it would be sufficient to also maintain compliance with SO_2 NAAQS impacts. This proposed limit/plan was issued for public comment on November 30, 2016. Once finalized, it will be submitted to Kentucky for inclusion in the SIP.

On August 10, 2015, EPA finalized requirements referred to as the Data Requirements Rule ("DRR") for a subsequent phase to assess the attainment status of areas near large sources of SO_2 emissions that did not have adequate ambient monitoring and that were not included in the April 2015 notifications. The DRR required facilities to assess attainment by either modeling or ambient monitoring that had SO_2 emissions in 2014 of 2,000 tons or greater. The Companies received notification from KDAQ dated October 22, 2015, that Trimble County and Ghent would need to provide an attainment assessment under the DRR. Air dispersion modeling has indicated the areas near both facilities are in attainment with the NAAQS. The modeling was submitted by the Companies and is currently under evaluation by the EPA.

Additionally, by Consent Decree entered on January 7, 2017, EPA is obligated to issue an Integrated Science Assessment for the SO_2 NAAQS by December 14, 2017, sign a notice of proposed rulemaking for any revision of the SO_2 NAAQS by May 25, 2018, and sign a final rulemaking by January 28, 2019. The Companies will be following these developments and assessing their impacts on operating facilities.

NO_2

The EPA published a final rule that revised the primary NAAQS for NO_2 on February 9, 2010. It became effective on April 12, 2010. EPA adopted a new 1-hour standard of 100 ppb and retained the existing annual average standard of 53 ppb. Based on existing air quality data in Kentucky, all areas are currently well below these standards. Nevertheless, the new rule stipulated the establishment of additional new air quality monitor locations. Emphasis is to be placed on locating these monitors near major roadways in large cities where the highest concentrations are expected; but additional monitors to represent community-wide air quality may also be required in large cities. The additional monitors are to be installed in phases between 2014 and 2017 and will be utilized in development of future revisions to the NO_2 standard. However, on December 22, 2016, EPA promulgated a rule that removed the requirement for near-road NO_2 monitoring for populations areas between 500,000 and one million people.

EPA is also planning to evaluate whether changes to Prevention of Significant Deterioration ("PSD") air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

Additionally, by Consent Decree entered on January 7, 2017, EPA is obligated to review the NO_2 NAAQS again by July 14, 2017 and sign a notice of final rulemaking for any revision by April 6, 2018. The Companies will be following these developments and assessing their impacts on operating facilities.

Ozone

Jefferson County was designated "unclassifiable/attainment" with the 2008 NAAQS for ozone of 0.075 parts per million ("ppm") in May 2012.

On January 7, 2010, EPA proposed an even lower primary ozone standard within a range of 0.060 and 0.070 ppm measured over eight hours. At the same time, EPA proposed a new seasonal secondary ozone standard in the range of 7 to 15 ppm. On September 2, 2011, President Obama announced that EPA was going to withdraw the draft regulation. EPA subsequently withdrew their proposal due to insufficient data and issued a new proposal on November 25, 2014. The final regulation establishing the new standard at 0.070 ppm was published in the Federal Register on October 26, 2015 and became effective on December 28, 2015. Kentucky has up to two years from that date to establish attainment status designations. Kentucky will then have one year to submit a SIP incorporating the new NAAQS and plans for bringing all areas into attainment with the new standard. EPA will then have one year to approve Kentucky's SIP submittal and non-attainment areas will have from 2021 to 2037, depending on the severity of non-attainment, to obtain attainment status following EPA's approval. On September 30, 2016, Kentucky submitted their recommendations for classifications. They recommended that Boone, Campbell, and Kenton counties be designated as "nonattainment" and that all other counties be designated as "unclassifiable/attainment". EPA's final determination on designations will be based on 2014-2016 quality assured monitoring data which may have an effect on Kentucky's recommended designations.

PM / PM$_{2.5}$

EPA published a new NAAQS for $PM_{2.5}$ in January 2013 that lowered the 24-hour standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$. An audit conducted by the KDAQ in 2013 found data quality issues with the $PM_{2.5}$ monitors operated by the LMAPCD. Although Jefferson County was classified as non-attainment for the 1997 24-hr standard, KDAQ recommended a status of attainment/unclassifiable based on valid 2011 to 2013 data and the general downward trend of ozone. Additionally, KDAQ recommended the use of data from monitors located in Southern Indiana near Jefferson County in support of attainment status.

On April 7, 2015, EPA published a correction for Jefferson County including a portion of Bullitt County to a designation of "unclassifiable" and "unclassifiable/attainment" for the remainder of Kentucky based on monitoring data in Kentucky and nearby areas from 2012 through 2014. The next 3-year assessment will be conducted following availability of 2016 data to establish a 3-year average consisting of 2014-2016 data. As a result of the shutdown of coal-fired generation at the Cane Run facility in 2015 and the installation of pulse jet fabric filters on the Mill Creek coal-fired units by 2016, concerns with the $PM_{2.5}$ attainment status are expected to be minimized. Additionally in March 2015, EPA proposed an option for resolution of attainment issues between the 1997 and the 2006 standard, by allowing achievement of attainment status with the 2013 standard to satisfy the attainment status of the 1997 standard, considering the 2013 standard is more restrictive. On August 24, 2016, EPA resolved the attainment issues by revoking the 1997 primary standard because the 2013 standard was lower.

Greenhouse Gases

On September 22, 2009, EPA issued its mandatory Greenhouse Gas ("GHG") emissions reporting rule. Facilities with CO_2 emissions of more than 25,000 metric tons or an aggregated maximum rated heat input capacity of more than 30 MMBtu/hour are subject to the GHG emissions reporting rule. Annual reporting to EPA began March 31, 2011. Sources required to report include: power plants, miscellaneous stationary combustion sources, and emissions pertaining to the gas supplied to customers of the Companies. On November 2, 2010, the reporting regulation was expanded to include reporting of Sulfur Hexafluoride (SF_6) emissions from electric transmission and distribution equipment, as well as methane, carbon dioxide, and nitrogen oxide emissions from natural gas processing plants, natural gas transmission compression operations, natural gas underground storage, and natural gas distribution activities. Reporting for these activities began with the 2010 operating year.

On March 13, 2010, EPA issued the GHG "Tailoring Rule" which became effective on January 2, 2011. This rule sets thresholds for requiring permitting of GHG emissions. Between January 2011 and June 2011, sources subject to any other PSD rule that undergo modification will have to get a permit for any applicable GHG emissions if they total more than 75,000 tpy of CO_2. The threshold was set at 100,000 tpy of CO_2 emissions for new sources and 75,000 tpy CO_2 emissions for modified sources effective by July 2011. With promulgation of the GHG "Tailoring Rule" in March 2010, effective July 2011, any new source with maximum potential emissions of CO_2 greater than 100,000 tpy or a modification to a new source that is evaluated to cause an increase in CO_2 emissions greater than 75,000 tpy will trigger PSD if any other PSD pollutant is triggered. If triggered, the source must include an analysis of best available control technology ("BACT") during permitting activities.

On June 25, 2013, President Obama announced his "Climate Action Plan" which laid out a timeline and targets for regulatory development to reduce GHG emissions. In response, EPA issued a proposed new source performance standard ("NSPS") for GHG emissions from new fossil fuel fired electric generation sources. The proposal was published in the Federal Register on January 8, 2014 and establishes the effective date for the specific standards limiting CO_2 emissions from new fossil fuel fired electric generating facilities including coal fired, natural gas fired (if greater than 1/3 of the maximum potential generation is used on the grid), and integrated gas combined cycle units. The currently proposed GHG NSPS would establish partial carbon collection and storage ("PCCS") as the best system of emission reduction.

EXHIBIT 2

The final rule was published by EPA in the Federal Register on October 23, 2015. EPA's final determination of the NSPS for CO_2 relative to these sources is 1,400 lb CO_2/MWh (gross) based on supercritical pulverized coal unit ("SCPC") with partial carbon capture and storage ("CCS") of approximately 16% with bituminous coal as the best system of emission reduction ("BSER") for newly constructed units. As an alternative for BSER, EPA determined a new SCPC unit co-firing natural gas could also meet the standard. The limit in the final rule is less stringent than the proposed rule of 1,100 lb CO_2/MWh (gross) due to an assumed higher level of partial CCS in the proposed rule.

EPA based the final standards for newly constructed or reconstructed stationary combustion turbines on BSER represented by efficient NGCC technology for base load natural gas fired units and clean fuels for non-base load and multi-fuel-fired units. The published final limits are 1,000 lb CO_2/MWh (gross) or 1,030 lb CO_2/MWh (net) for base load natural gas-fired units (base load rating of $\geq$ 250 MMBtu/h and > 25 MW (net) of electricity to the grid). For multi-fuel-fired units based on the percentage of co-fired natural gas, the standard is 120 lb CO_2/MMBtu for non-base load natural gas-fired units, and 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units based on the percentage of co-fired natural gas.

In June 2014, EPA proposed a GHG NSPS for modified or reconstructed existing sources that would set an emission rate in units of lbs of CO_2 per MWh (net) that is based on a 2% improvement of the best year from a look-back period from 2002 to date of modification or reconstruction. The proposal would set minimums (floors) of 1,900 and 2,100 lb CO_2 per MWh (net) for coal-fired units greater than 2,000 MMBtu/h and 2,100 MMBtu/h respectively. The rule also proposed GHG NSPS for combustions turbines with greater than 33% of the nameplate capacity utilized for electric generation that are modified or reconstructed to meet emission an emission limit of 1,000 and 1,100 lb CO_2 per MWh (net) for units greater than 850 MMBtu/h and less than 850 MMBtu/h, respectively.

EPA's final requirements for reconstructed combustion turbines were included in their final published rule with newly constructed combustion turbine as described above. The final rule was published by EPA in the Federal Register on October 23, 2015, for modified fossil fuel fired steam generating units and integrated gas combined cycles that perform a modification on or after the date of publication of the proposed standards, June 18, 2014. The NSPS for modified existing sources becomes applicable if a modification occurs that results in an increase in CO_2 hourly emissions of more than 10 percent. BSER for modified sources was determined by EPA to represent the most efficient generation at the affected EGU achievable through a combination of "best operating practices and equipment upgrades". The final standards of performance for CO_2 relative to these sources is a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). The emission limit will be no more stringent than 1,800 lb CO_2/MWh (gross) for sources with heat input > 2,000 MMBtu/hr or 2,000 lb CO_2/MWh (gross) for sources with heat input ≤ 2,000 MMBtu/hr. The final rule places a more stringent maximum limit on modified sources than the proposed rule that included limits of 1,900 and 2,100 lb CO_2/MWh (gross) for units > 2,000 and ≤ 2,000 MMBtu/hr respectively. Additionally, EPA proposed regulations in June 2014 for GHG performance standards applicable to existing fossil fuel fired electric generating units (ESPS) that commenced construction prior to January 8, 2014. The proposed regulation would reduce CO_2 emissions by 30% from 2005 by 2030 with interim reductions beginning in 2020. The regulation was proposed under Section 111(d) of the Clean Air Act as guidelines for development of SIPs to meet "state-specific" emission rate targets in units of lb CO_2 per MWh (net), with an option to convert the target to units of tons CO_2 per year. The proposed emission-rate targets for Kentucky are 1,763 lb CO_2 per MWh (net) by 2030 with an interim emission rate of 1,844 lb CO_2 per MWh (net) by 2020.

On October 23, 2015 EPA published the final ESPS—the final Clean Power Plan—in the Federal Register. The final rule decreased Kentucky's and many other states' emission targets from those of the proposed rule, primarily due to changes in EPA's analyses of best system of emission reductions (BSER) based on regional considerations instead of state-specific considerations. In shifting from a state-specific BSER to a regional based BSER, the building blocks utilized for Kentucky assume a greater utilization of existing NGCC generation and renewable energy (although not necessarily located in Kentucky). Development and use of demand-side management and energy efficiency was eliminated due to concerns that EPA lacked authority to incorporate it in the emission reduction targets. The emission rate goal in units of lb CO_2/MWh(n) for Kentucky was reduced in the final rule from 1,844 to 1,509 in the interim compliance period and from 1,763 to 1,286 by 2030.

With the final rule, the beginning of the Interim compliance period was shifted from 2020 to 2022. Each state can craft their own emission reduction trajectory, however milestones must be evaluated for 2022-2024, 2025-2027, and 2028-2029 with the requirement that affected EGUs in the state collectively meet the equivalent reductions of the interim limits. State plans must contain procedures to ensure the required CO_2 reductions are being accomplished and no increases in emissions relative to each state's planned emission reduction trajectory are occurring.

In response to applications for stay by numerous parties, on February 9, 2016, the Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule. The stay will remain in effect pending Supreme Court review if such review is sought.

Associated with the final rule for existing source performance standards, EPA published a proposed implementation plan on October 23, 2015, that can be adopted by states or utilized by EPA in the event a state does not submit a timely and acceptable compliance plan to implement the ESPS rule. EPA's proposed implementation plan includes allocations of CO_2 emissions for each state reflective of the final ESPS rule and the requirement to limit emissions of CO_2 from any new sources of generation that might be utilized in place of existing generation. The Companies submitted comments to EPA on January 21, 2016. On March 28, 2017, President Trump signed an executive order to review the CPP for the potential to revise or withdraw the rule.

Coal Combustion Residuals

The EPA issued a new coal combustion residuals ("CCR") regulation on December 19, 2014, with an effective date of October 19, 2015. The new rule makes changes in the permitting and management practices for CCR from coal-ash and flue-gas desulphurization ("FGD") systems whether they are managed in ash treatment basins (ash ponds) or landfills.

EPA chose to regulate CCRs as a non-hazardous solid waste under Resource Conservation and Recovery Act Subtitle D with state oversight of federal minimum standards. All CCR storage units must either close within three years or may remain active by installing groundwater monitoring wells and performing dam integrity testing. If groundwater contamination is found around an unlined storage unit, the unit must stop receiving CCR within six months and properly close within five years. If siting criteria or dam safety factors do not meet the minimum requirements, the unit must close. Data collection has begun and groundwater monitoring plans have been initiated.

part 2

17051000005

Exhibit 3

17051000 5

2017 Resource Assessment

PPL companies

Energy Planning, Analysis, and Forecasting
May 2017

Table of Contents

1 Executive Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") filed their 2016 Integrated Resource Plan ("IRP") with the Virginia State Corporation Commission on May 1, 2016. In October 2015 and November 2015, respectively, the U.S. Environmental Protection Agency ("EPA") published the final versions of the Clean Power Plan ("CPP") and Effluent Limitation Guidelines ("ELG"). The ELG specifies a compliance deadline of no later than December 2023. The Companies are evaluating ELG compliance options for each coal-fired generating station to determine the most cost-effective compliance plan. On April 13, 2017, the EPA announced that it will reconsider the ELG regulations and that it intends to stay the rule's upcoming deadlines, pending further review. However, because this review is not likely to impact Kentucky's state water quality standards, the review is not expected to materially affect the Companies' future plans for wastewater compliance. The future of the CPP is also uncertain: on February 9, 2016, the U.S. Supreme Court issued an order staying the CPP pending all appellate review of the CPP, including any review by the Court. On March 28, 2017, President Trump signed an executive order to review the CPP for the potential to revise or withdraw the rule.

The Companies' analysis of ELG compliance options is ongoing. Given this fact and the uncertainty associated with the CPP, this Resource Assessment assumes that CPP and ELG compliance costs will not result in any changes to the Companies' generating portfolio.

The Companies continually evaluate their resource needs and the need for major capital improvements. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost resource plan may be revised as conditions change and as new information becomes available. Even though the resource assessment represents the Companies' analysis of the best options to meet customer needs at this given point in time, this plan will be reevaluated and updated as warranted.

The Companies' 2017 Resource Assessment was completed in two parts. First, the Companies developed a forecast of peak demand and energy requirements to assess the need for additional generating capacity. Then, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Because the Companies do not have a capacity need over the 15-year planning horizon, a detailed expansion planning analysis was not performed.

1.1 Capacity and Energy Need

Table 1 details the Companies' current capacity supply/demand balance for the 15-year planning period.[1] The forecast peak load declines from 2018 to 2019 due to the termination of several municipal contracts.[2] As discussed in the Companies' 2014 Reserve Margin Study, the Companies target a minimum 16 percent reserve margin (above peak load after adjusting for demand-side management ("DSM") programs) for the purpose of developing expansion plans. In Table 1, the Bluegrass Agreement

[1] For purposes of calculating reserve margin, loads subject to the Companies' curtailable service rider are considered supply-side resources.

[2] The non-coincident peak demand for these municipals is approximately 325 MW. The reduction in the Companies' peak demand from 2018 to 2019 reflects the reduction in the municipal customers' coincident peak demand as well as other factors.

(165 MW) is included in "Firm Purchases" along with the Companies' share of Ohio Valley Electric Corporation ("OVEC") (152 MW).[3] Considering these firm purchases, along with 364 MW of demand reduction from DSM programs by 2020, and 130 MW of curtailable load from curtailable service rider customers, the Companies do not expect to have a long-term need for capacity in the 15-year planning period.

Table 1 – Resource Summary (MW, Summer)

	2017	2018	2019	2020	2021	2029	2030	2031
Forecast Peak Load	7,137	7,183	6,935	6,912	6,897	6,968	6,986	6,995
DSM	(331)	(378)	(383)	(364)	(364)	(364)	(364)	(364)
Net Peak Load	6,806	6,805	6,552	6,548	6,533	6,604	6,622	6,631
Existing Resources[4]	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842
Planned/Proposed Resources	0	0	0	0	0	0	0	0
Firm Purchases[5]	317	317	152	152	152	152	152	152
Curtailable Load	130	130	130	130	130	130	130	130
Total Supply	8,289	8,289	8,124	8,124	8,124	8,124	8,124	8,124
Reserve Margin ("RM")	21.8%	21.8%	24.0%	24.1%	24.4%	23.0%	22.7%	22.5%
RM Shortfall (16% RM) *	394	395	524	529	546	464	443	432

*Negative values denote reserve margin shortfalls.

While meeting customers' energy demand at the peak hour is critical, it is also vital to reliably serve their energy needs at all hours at the lowest reasonable cost. As seen in Table 2, after the 2019 termination of several municipal customers' contracts, energy requirements are forecast to increase by 0.57 TWh from 2020 to 2031.[6] The compound annual growth rate ("CAGR") over this period is 0.15 percent.

Table 2 – Energy Requirements (TWh, After DSM)

	2017	2018	2019	2020	2021	2029	2030	2031
Energy Requirements	35.0	35.0	34.0	33.5	33.5	33.9	34.0	34.0

The Companies also considered "low" and "high" load scenarios. Even under the "high" load scenario, the Companies do not expect to have a long-term need for capacity in the 15-year planning period. Therefore, absent significant unit retirements, the Companies do not expect to add new generating resources in its least-cost plan to reliably meet load requirements in the foreseeable future.

[3] The net summer rating for the Companies' share of OVEC is 172 MW; however, 152 MW is expected to be reliably available at the time of summer peak.

[4] Existing resources include the addition of Brown Solar in June 2016. 80% of the capacity of Brown Solar is assumed to be available at the time of peak.

[5] Firm Purchases include the Companies' share of OVEC as well as the planned capacity purchase and tolling agreement with Bluegrass for 165 MW through April 2019.

[6] Energy requirements represent the amount of generated energy needed to serve customers' energy needs, inclusive of transmission and distribution losses.

Sources of uncertainty in the Companies' forecast include the pace of economic growth, the penetration of electric vehicles, and the penetration of distributed energy resources (e.g., private solar). The penetration of electric vehicles and distributed energy resources is currently very low; the Companies will continue to monitor any developments in these areas.

1.2 Supply-Side Screening Analysis

Although the Companies do not forecast a long-term capacity need, the Companies completed a review of current technology costs as part of this Resource Assessment to provide an update on the current status and relative costs of the most viable generation resources.

Over the past several years, the cost of renewable generation has continued to fall while the cost of other types of generation has remained generally stable. Despite this fact, the costs of renewable generation remain higher than fossil generation technologies. The abundance of low cost natural gas supply resulting from advancements in natural gas drilling technologies coupled with relatively low capital and operating costs continue to support the economics of natural gas combined cycle ("NGCC") technology. However, with tax incentives and renewable energy certificates ("RECs"), both photovoltaic ("PV") solar and wind technologies can be cost competitive in certain circumstances. In the longer term, energy storage technology in the form of batteries may prove to be a viable alternative in scenarios with low load growth.

In the screening analysis, the levelized cost of each technology option was calculated at various levels of utilization (i.e., capacity factor). In addition to the level of utilization, the levelized cost is impacted by the uncertainty in capital cost, fuel cost, and unit efficiency. As a result, the technology options were evaluated over 270 cases. All cases assumed REC market prices for wind and solar as well as a 10 percent investment tax credit for solar PV.[7]

Table 3 lists the technology options that were ranked among the top four least-cost technology options in at least one of the 270 cases. The "2x1 NGCC G/H Class – DF" option ranked among the top four least-cost options in 269 of the 270 cases, and the "2x1 NGCC G/H-Class" option was least-cost in 110 cases and ranked among the top four least-cost options in 228 cases.[8] The option to install three F-Class Simple-Cycle Combustion Turbines ("SCCTs") ("SCCT F-Class – Three Units") was least-cost in 52 cases. The "2x1 NGCC G/H-Class" option was the best option for meeting intermediate and base load energy needs. The "SCCT F-Class – Three Units" option was the best option for meeting peak energy needs. The advanced battery energy storage, solar PV, and wind technology options were ranked among the top four least-cost technology options in multiple cases.

[7] In December 2015, the Business Energy Investment Tax Credit was amended with expiration dates and gradual step-downs of the credits by 2022. For more details, *see* https://energy.gov/savings/business-energy-investment-tax-credit-itc.

[8] "DF" refers to duct firing, which is explained in further detail in Section 4.2.1.1.

Table 3 – Screening Results (Technology Options Ranked Among Top Four Least-Cost)

Generation Technology Option	# Occurrences 1st	2nd	3rd	4th	Total
2x1 NGCC G/H-Class – DF	0	23	117	129	**269**
2x1 NGCC G/H-Class	110	87	21	10	**228**
2x1 NGCC F-Class	0	82	76	20	**178**
Adv. Battery Energy Storage	58	33	43	30	**164**
SCCT F-Class – Three Units	52	9	5	5	**71**
2x1 NGCC F-Class – DF	0	0	0	68	**68**
Wind	38	3	1	3	**45**
SCCT F-Class – One Unit	0	24	7	1	**32**
Solar Photovoltaic	12	9	0	1	**22**
1x1 NGCC G/H-Class	0	0	0	3	**3**

2 Existing and Planned Generating Resources

Table 4 contains unit data for existing and planned generating resources. E.W. Brown Solar was commissioned in June 2016. No retirements are assumed during the planning period.

Since the last IRP (May 2016), the Companies installed a fabric filter baghouse ("baghouse") new flue gas desulfurization system ("FGD") on Mill Creek 3. No additional changes to emission controls, operating characteristics, unit ratings, unit availabilities, or fuel supply are assumed for existing units over the planning period.

Table 4 – Existing and Future Generating Resources

Plant Name	Unit No.	Location	Status	Operation Date	Facility Type	Net Capability (MW) 2016/17 Winter	Net Capability (MW) 2016 Summer	Entitlement KU	Entitlement LGE	Fuel Type	Unit Type	Scheduled Upgrades and Retirements
Cane Run	7	Louisville, KY	Existing	2015	Turbine	683	662	78%	22%	Gas	Base/Intermediate	None
	11			1968		14	14		100%	Gas / Oil	Peaking	
Dix Dam	1-3	Burgin, KY	Existing	1925	Hydro	31.5	31.5	100%		Water	Hydro	None
E. W. Brown Coal	1	Burgin , KY	Existing	1957	Steam	107	106	100%		Coal (Rail)	Base/Intermediate	None
	2			1963		168	166					None
	3			1971		413	409					None
E.W. Brown-ABB 11N2	5			2001	Turbine	130	130	47%	53%	Gas	Peaking	None
E.W. Brown-ABB GT24	6			1999		171	146	62%	38%	Gas / Oil	Peaking	
	7			1999		171	146					
E.W. Brown-ABB 11N2	8			1995		128	121	100%				
	9			1994		138	121					
	10			1995		138	121					
	11			1996		128	121					
E.W. Brown Solar	1			2016	Solar	0	8	61%	39%	Solar	Solar PV	None
Ghent	1	Ghent, KY	Existing	1974	Steam	476	474	100%		Coal (Barge)	Baseload	None
	2			1977		475	493					None
	3			1981		478	485					None
	4			1984		487	465					None
Haefling	1	Lexington, KY	Existing	1970	Turbine	14	12	100%		Gas / Oil	Peaking	None
	2			1970		14	12					
Mill Creek	1	Louisville, KY	Existing	1972	Steam	300	300		100%	Coal (Barge & Rail)	Baseload	None
	2			1974		295	297					None
	3			1978		394	391					None
	4			1982		486	477					None
Ohio Falls	1-8	Louisville, KY	Existing	1928	Hydro	Run of River (38/60)			100%	Water	Hydro	4 MW upgrade 2016-2017
OVEC	N/A	Gallipolis, OH Madison, IN	Existing	1955	Steam	178	172	31%	69%	Coal	Base/Intermediate	None
Paddy's Run	11	Louisville, KY	Existing	1968	Turbine	13	12		100%	Gas	Peaking	None
	12			1968		28	23					
	13			2001		175	147	47%	53%			
Trimble County Coal (75%)	1	Bedford, KY	Existing	1990	Steam	493 (370)	493 (370)	0%	75%	Coal (Barge)	Baseload	None
	2			2011		760 (570)	732 (549)	61%	14%			None
Trimble County-GE7FA	5			2002	Turbine	179	159	71%	29%	Gas	Peaking	None
	6			2002		179	159					
	7			2004		179	159	63%	37%			
	8			2004		179	159					
	9			2004		179	159					
	10			2004		179	159					
Zorn	1	Louisville, KY	Existing	1969	Turbine	16	14		100%	Gas	Peaking	None
Planned Resources												
Bluegrass Capacity Purchase and Tolling Agreement	1	La Grange, KY	Existing	2015	Turbine	165	165		100%	Gas	Peaking	Agreement terminates on April 30, 2019.

* The ratings for Dix Dam, Ohio Falls, and E. W. Brown Solar reflect the assumed output for these facilities during the summer and winter peak demands.

3 Capacity and Energy Need

The determination of the Companies' capacity and energy need begins with a robust forecast of peak demand and energy requirements.[9]

3.1 Economic Outlook – April 2016[10]

Economic growth in the Virginia service territory remains weak as mining sector declines continue to influence all sectors. The residential sector continues to feel the effects with a 3 percent decline in households in the Virginia territory since 2010; small population declines are projected to continue through the planning period. Economic growth remains on a slow but steady upward trajectory in the LG&E/KU service territory driven predominantly by stronger growth in the urban areas of Kentucky. Kentucky's economy grew at 2.7 percent on a seasonally-annualized basis during the fourth quarter of 2015, bringing annual economic growth to 1.1 percent for 2015 overall. This compares to 2.4 percent for the US, though much of this disparity was due to a 4.8 percent decline in Kentucky growth during the first quarter of 2015. IHS is now projecting KY economic growth to average 2.1 percent from 2016-2020, below last quarter's forecast of 2.3 percent.

The Commonwealth of Kentucky added over 34,000 jobs in 2015, the highest annual figure since 1999, pointing toward a more positive outlook for the state's economic prospects. However, job growth sputtered through the early part of 2016. Kentucky lost 3,900 total jobs through May 2016 and approximately twice that number of goods-producing jobs (Mining and Logging: -1,400, Construction: -3,900, Manufacturing: -1,500).

3.1.1 Mining Sector and Impact on Appalachia

One area where the economy continues to struggle is in the mining sector. Kentucky lost 3,300 mining and logging jobs in 2015, and has lost 49 percent (12,600) of its mining and logging jobs since January 2009. The hardest hit areas of the Companies' service territories have been Wise County in southwestern Virginia and Bell and Harlan counties in southeastern Kentucky. Combined, these three counties accounted for 4.7 percent of the service territory's large commercial and industrial electricity sales in 2011. The number has since shrunk to 3.1 percent in 2015, a decline of 261 GWh.

The loss of jobs has led to net migration out of these counties in recent years. In Virginia, Wise County lost an estimated 1,600 residents between 2011 and 2015, the second worst absolute decline in Virginia. The story was similar in Kentucky as Harlan County lost 4,780 residents between 2000 and 2014, the second worst absolute decline among the state's 120 counties. Bell County did not fare much better, losing 2,250 residents over the timeframe, the sixth worst absolute decline in the state. Between 2011 and 2015, Harlan lost an estimated 1,800 residents (third worst absolute decline over this period) while Bell lost an estimated 1,300 residents (fourth worst).

The downward trend for these counties remains intact moving forward according to IHS forecasts. However, the rate of decline is expected to slow from 1,000 residents per year for the three counties from 2011 to 2015 to just over 600 residents per year from 2016 through 2020.

---

[9] A detailed summary of the forecast inputs and models is contained in Appendix B - Electric Sales & Demand Forecast Process.

[10] This economic outlook was developed in April 2016 and is consistent with the inputs to the peak demand and energy requirements forecasts.

3.1.2 Manufacturing Sector

Though the mining sector's struggles continue, manufacturing growth remains strong in Kentucky. This sector contributed 21.3 percent of the state's added jobs in 2015, second only to the Professional and Business sector. This is particularly impressive since manufacturing only accounted for 12.7 percent of the state's jobs as of the end of 2014.

The growth prospects in the manufacturing sector remain promising. In December, Ford announced a $1.3 billion investment in Louisville's Kentucky Truck Plant to support the new 2017 F-Series Super Duty line of trucks. Regional aluminum processing plants have been expanding to meet component demand. Toyota has also planned expansions, including a new paint facility and new offices for re-search and development. Toyota also began producing the Lexus ES350 at the Georgetown plant in October 2015. Full production of the ES350 began in June 2016, and Toyota expects to produce 50,000 ES350s per year. In total, the Ford and Toyota expansions are forecast to increase electricity demand by 39 to 55 MVA. Similarly, IHS's current forecast for light vehicle sales show continued growth through 2017, before declining slightly to 2015 levels by 2020.

3.1.3 Residential Summary

Since the impacts of the great recession started to abate in early 2012, the growth in the economic regions of Louisville and Lexington have been clearly differentiated from the more rural parts of the service territory. Three year CAGRs for residential customers of 0.5% in Lexington and 0.4% in Louisville or approximately 7,000 customers in each region continue to be dampened by a decrease of 0.3% or 2,000 customers across all other regions.

As of mid-2015, 58% of the statewide payroll was earned in the Louisville and Lexington regions. Total job growth rates in these regions since the end of the last recession have surpassed the national average. However, the Mountain region (primarily Harlan and Bell counties) has fewer jobs than six years ago with payrolls declining 13% over the same period. Breaking this down to a county level, 47% of job growth statewide occurred in Jefferson and Fayette counties. Ten primarily urban counties accounted for 85% of job growth with fifty-six counties experiencing net job loss.

Looking forward, employment growth projections by occupation support this with the highest growth in healthcare, personal care, and social services and declines in farming, fishing, and forestry industries through 2022. Underlying these numbers are trends towards an aging population, a continued increase in levels of educational attainment, and a growth in the foreign born population which will all further impact migration trends and housing preferences.

3.2 Electric Load and Peak Demand Forecast

Combined LG&E, KU, and ODP load is expected to grow at a relatively slower rate in the coming years compared to previous forecasts. The slower pace of growth in the current forecast is largely due to downward revisions to the load forecasts for the residential and small commercial classes.

Residential use-per-customer levels are forecast to remain relatively consistent compared to previous years across the service territory, but population growth is now seen as slower than previously forecasted. In the small commercial sector, customer growth is forecast to accelerate, but use-per-customer levels continue to fall. As a result, both of these major sectors, which together account for roughly two thirds of total load in the service territory, are contributing to slower load growth across the Companies' service territories than previously forecasted.

The industrial sector remains relatively consistent with the previous plan and is forecast to show consistent growth in the years ahead. The closure of mines in eastern and western Kentucky, along with the ODP region of Virginia, remains a persistent downside risk in the forecast; indeed, in Virginia the Companies are forecasting decreasing load over the planning period. However, manufacturers in Kentucky, particularly in the auto sector, are healthy. Planned expansions at some plants (Toyota, for example) are expected to more than offset losses from the mining sector, providing positive trend growth.

From 2016-2020, the Companies' load is expected to decline at a pace of 0.4 percent per year, compared 0.1 percent previously, as a result of the 2019 termination of several municipal customers' contracts. From 2020 to 2031, the Companies' load grows at a CAGR of 0.15 percent.

Summer peak demand forecasts have been reduced as a result of the lower energy forecast. Table 5 contains the Companies' base, high, and low peak demand forecasts. From 2020-2031, after the loss of the municipal customers, peak demand in the base forecast is expected to grow at a CAGR of 0.1 percent. Sources of uncertainty in the Companies' peak demand forecast include the pace of economic growth, the penetration of electric vehicles, and the penetration of distributed energy resources (e.g., private solar). The penetration of electric vehicles and distributed energy resources is currently very low; the Companies will continue to monitor any developments in these areas.

Table 5 – Base, High, and Low Peak Demand Forecasts (Combined Companies, MW)

Year	Low	Base	High
2017	6,640	6,806	6,972
2018	6,639	6,805	6,971
2019	6,390	6,552	6,714
2020	6,385	6,548	6,710
2021	6,369	6,533	6,698
2022	6,369	6,543	6,716
2023	6,358	6,548	6,738
2024	6,348	6,560	6,772
2025	6,332	6,561	6,791
2026	6,320	6,562	6,803
2027	6,303	6,554	6,805
2028	6,325	6,583	6,842
2029	6,339	6,604	6,868
2030	6,353	6,622	6,891
2031	6,359	6,631	6,904

Table 6 through Table 9 list the most recent three-year history and 15-year forecast of energy sales (kWh) by customer class for KU as a whole and for the ODP service territory. Please see Schedules 1, 5, and 6 for the most recent three-year history and 15-year forecast of peak load, coincident peak load and associated non-coincident peak load for summer and winter seasons of each year, annual energy forecasts, and resultant reserve margins.

Table 6 – KU Calendar Actual Sales by Jurisdiction (GWh)

	2014	2015	2016
Kentucky Retail	18,889	18,280	18,146
Kentucky Wholesale	1,886	1,855	1,876
Virginia Retail	836	767	735
Total System	21,610	20,902	20,757

Table 7 – KU Calendar Forecast Sales by Jurisdiction (GWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Kentucky Retail	18,314	18,333	18,341	18,332	18,338	18,343	18,360	18,380	18,376	18,365	18,369	18,422	18,479	18,539	18,576
Kentucky Wholesale	1,846	1,834	896	431	434	438	442	446	450	454	457	460	464	467	470
Virginia Retail	766	747	744	738	743	731	722	723	717	715	709	708	706	704	702
Total System	20,925	20,914	19,982	19,501	19,515	19,511	19,523	19,549	19,543	19,533	19,535	19,591	19,649	19,711	19,748

Table 8 – ODP Calendar Actual Sales by Class (GWh)

	2014	2015	2016
Residential	406	373	369
Commercial	189	193	193
Industrial/Mine Power	165	126	99
Lighting	1	2	2
Public Authority/Municipal Pumping	75	73	73
Total System	836	767	735

Table 9 – ODP Calendar Forecast Sales by Class (GWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential	375	368	367	362	357	354	351	350	346	344	342	339	337	335	332
Schools	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
General Service	88	86	86	85	84	84	83	83	82	81	81	80	80	80	79
Large Power	272	261	260	260	270	263	257	259	258	258	256	257	258	259	259
Lighting	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Municipal Pumping	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total System	766	747	744	738	743	731	722	723	717	715	709	708	706	704	702

3.3 Resource Summary

Nine KU municipal customers provided notices of termination of their wholesale power agreements in April 2014. The wholesale power contract with the City of Paris provided for a 3-year termination notice so their contract terminated on April 30, 2017. The remaining contracts will terminate on April 30, 2019.[11] To supplement the Companies' generating capacity through April 2019, the Companies entered into a capacity purchase and tolling agreement with Bluegrass Generation for 165 MW of capacity from May 2015 through April 2019. The Companies also commissioned a 10 MW PV solar facility at the E. W. Brown station ("Brown Solar") in June 2016.[12]

Table 10 details the Companies' current capacity supply/demand balance for the 15-year planning period.[13] As discussed in the Companies' 2014 Reserve Margin Study, the Companies target a minimum 16 percent reserve margin (above peak load after adjusting for DSM programs) for the purpose of developing expansion plans. In Table 10, the Bluegrass Agreement (165 MW) is included in "Firm Purchases" along with the Companies' share of OVEC (152 MW). Considering these firm purchases, along with 360 MW of demand reduction from DSM programs by 2020, and 130 MW of curtailable load from curtailable service rider customers, the Companies do not expect to have a long-term need for capacity in the 15-year planning period.

Table 10 – Resource Summary (Base Load Forecast, MW, Summer)

	2017	2018	2019	2020	2021	2029	2030	2031
Forecast Peak Load	7,137	7,183	6,935	6,912	6,897	6,968	6,986	6,995
DSM	(331)	(378)	(383)	(364)	(364)	(364)	(364)	(364)
Net Peak Load	6,806	6,805	6,552	6,548	6,533	6,604	6,622	6,631
Existing Resources[14]	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842
Planned/Proposed Resources	0	0	0	0	0	0	0	0
Firm Purchases[15]	317	317	152	152	152	152	152	152
Curtailable Load	130	130	130	130	130	130	130	130
Total Supply	8,289	8,289	8,124	8,124	8,124	8,124	8,124	8,124
Reserve Margin ("RM")	21.8%	21.8%	24.0%	24.1%	24.4%	23.0%	22.7%	22.5%
RM Shortfall (16% RM)*	394	395	524	529	546	464	443	432

*Negative values denote reserve margin shortfalls.

[11] The non-coincident peak demand for the remaining municipals is approximately 325 MW. The reduction in the Companies' peak demand from 2018 to 2019 reflects the reduction in the municipal customers' coincident peak demand as well as other factors.

[12] Brown Solar's expected output at the time of summer peak is 8 MW.

[13] For purposes of calculating reserve margin, loads subject to the Companies' curtailable service rider are considered supply-side resources.

[14] Existing resources include the addition of Brown Solar in June 2016. 80% of the capacity of Brown Solar is assumed to be available at the time of peak.

[15] Firm Purchases include the Companies' share of OVEC as well as the planned capacity purchase and tolling agreement with Bluegrass for 165 MW through April 2019.

While meeting customers' energy demand at the peak hour is critical, it is also vital to reliably serve their energy needs all year round at the lowest reasonable cost. As seen in Table 10, after the 2019 termination of several municipal customers' contracts, energy requirements are forecast to increase by 0.57 TWh from 2020 to 2031.[16] The CAGR over this period is 0.15 percent.

Table 11 – Energy Requirements (TWh, After DSM)

	2017	2018	2019	2020	2021	2029	2030	2031
Energy Requirements	35.0	35.0	34.0	33.5	33.5	33.9	34.0	34.0

The energy requirements in Table 11 were created by adding transmission and distribution losses to the Companies' sales forecast for LG&E and KU. The methods, models, and assumptions used to develop the load forecast for the service territory served by ODP are described in the most recent Levelized Fuel Factor filing.[17] In the proceedings of that case, this forecast was deemed reasonable.[18]

3.3.1 Low Load Scenario

Table 12 details the Companies' capacity supply/demand balance assuming the "low" load scenario for the 15-year planning period. Considering firm purchases, demand reduction from DSM programs, and curtailable load from curtailable service rider customers, the Companies do not expect to have a long-term need for capacity in the 15-year planning period.

[16] Energy requirements represent the amount of generated energy needed to serve customers' energy needs, inclusive of transmission and distribution losses.

[17] Please see CASE NO. PUE-2017-00024 - DIRECT TESTIMONY OF STUART A. WILSON, DIRECTOR - ENERGY PLANNING, ANALYSIS, AND FORECASTING, LG&E AND KU SERVICES COMPANY at pages 3-6 and Exhibit SAW-1 for a complete description of the load forecast methods, models, and assumptions used to prepare the load forecasts.

[18] Please see PRE-FILED TESTIMONY OF DIANE W. JENKINS, KENTUCKY UTILITIES COMPANY, D/B/A OLD DOMINION POWER COMPANY, CASE NO. PUE-2017-00024 at pages 4-7.

Table 12 – Resource Summary with Low Load (MW, Summer)

	2017	2018	2019	2020	2021	2029	2030	2031
Forecast Peak Load	6,972	7,017	6,773	6,750	6,733	6,703	6,717	6,723
DSM	(331)	(378)	(383)	(364)	(364)	(364)	(364)	(364)
Net Peak Load	6,640	6,639	6,390	6,385	6,369	6,339	6,353	6,359
Existing Resources[19]	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842
Planned/Proposed Resources	0	0	0	0	0	0	0	0
Firm Purchases[20]	317	317	152	152	152	152	152	152
Curtailable Load	130	130	130	130	130	130	130	130
Total Supply	8,289	8,289	8,124	8,124	8,124	8,124	8,124	8,124
Reserve Margin ("RM")	24.8%	24.9%	27.1%	27.2%	27.6%	28.2%	27.9%	27.8%
RM Shortfall (16% RM)*	586	588	712	717	736	771	755	748

*Negative values denote reserve margin shortfalls.

As seen in Table 13, after the 2019 termination of several municipal customers' contracts, energy requirements in the "low" load scenario are forecast to remain relatively flat from 2020 to 2031.[21]

Table 13 – Energy Requirements with Low Load (TWh, After DSM)

	2017	2018	2019	2020	2021	2029	2030	2031
Energy Requirements	34.1	34.1	33.1	32.6	32.6	32.5	32.5	32.6

3.3.2 High Load Scenario

Table 14 details the Companies' capacity supply/demand balance assuming the "high" load scenario for the 15-year planning period. Considering firm purchases, demand reduction from DSM programs, and curtailable load from curtailable service rider customers, even in the "high" load forecast scenario, the Companies have 109 MW of surplus capacity in 2031 and do not expect to have a long-term need for capacity in the 15-year planning period.

[19] Existing resources include the addition of Brown Solar in June 2016. 80% of the capacity of Brown Solar is assumed to be available at the time of peak.

[20] Firm Purchases include the Companies' share of OVEC as well as the planned capacity purchase and tolling agreement with Bluegrass for 165 MW through April 2019.

[21] Energy requirements represent the amount of generated energy needed to serve customers' energy needs, inclusive of transmission and distribution losses.

Table 14 – Resource Summary with High Load (MW, Summer)

	2017	2018	2019	2020	2021	2029	2030	2031
Forecast Peak Load	7,304	7,349	7,097	7,074	7,062	7,232	7,255	7,268
DSM	(331)	(378)	(383)	(364)	(364)	(364)	(364)	(364)
Net Peak Load	6,972	6,971	6,714	6,710	6,698	6,868	6,891	6,904
Existing Resources[22]	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842
Planned/Proposed Resources	0	0	0	0	0	0	0	0
Firm Purchases[23]	317	317	152	152	152	152	152	152
Curtailable Load	130	130	130	130	130	130	130	130
Total Supply	8,289	8,289	8,124	8,124	8,124	8,124	8,124	8,124
Reserve Margin ("RM")	18.9%	18.9%	21.0%	21.1%	21.3%	18.3%	17.9%	17.7%
RM Shortfall (16% RM)*	201	203	336	341	355	157	130	116

*Negative values denote reserve margin shortfalls.

As seen in Table 14, after the 2019 termination of several municipal customers' contracts, energy requirements in the "high" load scenario are forecast to increase by 1.18 TWh from 2020 to 2031.[24] The CAGR over this period is 0.31 percent.

Table 15 – Energy Requirements with High Load (TWh, After DSM)

	2017	2018	2019	2020	2021	2029	2030	2031
Energy Requirements	35.8	35.8	34.8	34.3	34.3	35.3	35.4	35.5

4 Supply-Side Screening Analysis

4.1 Introduction

The Companies' Resource Assessment considered 58 generation technology options. A detailed evaluation (using production costing computer models) of all technology options is impractical due to the significant amount of time required for computer simulation. Therefore, the purpose of the supply-side screening analysis is to identify a subset of the most competitive generation technology options.

Section 4.2 summarizes the generation technology options considered for meeting future capacity and energy needs. Organized by types, these technology options range from natural gas, coal-fired, waste-to-energy, renewable, energy storage, and nuclear technologies. Section 4.3 presents the key uncertainties that were considered in the analysis. Section 4.3.4 describes the methodology used to evaluate and compare the technology options, and Section 4.5 concludes with determining the least cost generation technology options.

[22] Existing resources include the addition of Brown Solar in June 2016. 80% of the capacity of Brown Solar is assumed to be available at the time of peak.

[23] Firm Purchases include the Companies' share of OVEC as well as the planned capacity purchase and tolling agreement with Bluegrass for 165 MW through April 2019.

[24] Energy requirements represent the amount of generated energy needed to serve customers' energy needs, inclusive of transmission and distribution losses.

4.2 Generation Technology Options

4.2.1 Technology Options Summary

The list of generation technology options evaluated in the 2017 IRP was unchanged from the 2016 IRP. With the exception of the advanced battery energy storage, solar PV, and wind technologies, the cost and performance characteristics of the generation technology options were estimated in 2013 by Burns & McDonnell, an engineering consulting firm. The Companies compared the Burns & McDonnell cost estimates to more recent cost estimates for a subset of the technologies considered and only the cost of the advanced battery energy storage, solar PV, and wind technologies were materially different.[25] Table 16 lists all the technology types considered, the generation technology options for each technology type, as well as the representative technology option the study used as a basis for the cost and performance estimates. Each technology type is discussed in more detail in the following sections.

Table 16 – Generation Technology Types

Technology Type	Generation Technology Option	Representative Technology Option
Natural Gas	SCCT Aeroderivative – One Unit	Simple-cycle GE LM6000 – One Unit
Natural Gas	SCCT Aeroderivative – Four Units	Simple-cycle GE LM6000 – Four Units
Natural Gas	Intercooled SCCT Aeroderivative – One Unit	Simple-cycle GE LMS100 – One Unit
Natural Gas	Intercooled SCCT Aeroderivative – Two Units	Simple-cycle GE LMS100 – Two Units
Natural Gas	SCCT E-Class – One Unit	Simple-cycle GE 7EA – One Unit
Natural Gas	SCCT E-Class – Three Units	Simple-cycle GE 7EA – Three Units
Natural Gas	SCCT F-Class – One Unit	Simple-cycle GE 7F-5 – One Unit
Natural Gas	SCCT F-Class – Three Units	Simple-cycle GE 7F-5 – Three Units
Natural Gas	Spark Ignition Reciprocating Engine – Six Units	Recip Engine - 100 MW – Six Units
Natural Gas	Spark Ignition Reciprocating Engine – Twelve Units	Recip Engine - 200 MW – 12 Units
Natural Gas	Simple-cycle Gas Microturbine – Five Units	Microturbine- 1 MW – Five Units
Natural Gas	Simple-cycle Gas Microturbine – Fifteen Units	Microturbine - 3 MW – Fifteen Units
Natural Gas	Molten-Carbonate Fuel Cell – Four Units	Fuel Cell - 10 MW – Four Units
Natural Gas	Molten-Carbonate Fuel Cell – Twelve Units	Fuel Cell - 30 MW – Twelve Units
Natural Gas	1x1 NGCC F-Class	Combined-Cycle 1x1 GE 7F-5
Natural Gas	1x1 NGCC F-Class – Duct Firing ("DF")	Combined-Cycle 1x1 GE 7F-5 - Fired
Natural Gas	1x1 NGCC G/H-Class	Combined-Cycle 1x1 MHI GAC
Natural Gas	1x1 NGCC G/H-Class – DF	Combined-Cycle 1x1 MHI GAC - Fired
Natural Gas	1x1 NGCC J-Class	Combined-Cycle 1x1 MHI JAC
Natural Gas	1x1 NGCC J-Class – DF	Combined-Cycle 1x1 MHI JAC - Fired
Natural Gas	2x1 NGCC F-Class	Combined-Cycle 2x1 GE 7F-5
Natural Gas	2x1 NGCC F-Class – DF	Combined-Cycle 2x1 GE 7F-5 - Fired
Natural Gas	2x1 NGCC G/H-Class	Combined-Cycle 2x1 MHI GAC
Natural Gas	2x1 NGCC G/H-Class – DF	Combined-Cycle 2x1 MHI GAC - Fired
Natural Gas	2x1 NGCC J-Class	Combined-Cycle 2x1 MHI JAC
Natural Gas	2x1 NGCC J-Class – DF	Combined-Cycle 2x1 MHI JAC - Fired
Natural Gas	3x1 NGCC F-Class	Combined-Cycle 3x1 GE 7F-5
Natural Gas	3x1 NGCC F-Class – DF	Combined-Cycle 3x1 GE 7F-5 - Fired
Natural Gas	3x1 NGCC G/H-Class	Combined-Cycle 3x1 MHI GAC

[25] The battery costs were derived using costs for lithium ion batteries from Electric Power Research Institute's ("EPRI") "Energy Storage Cost Summary for Utility Planning," December 2016. The solar PV and wind costs were derived from Lazard's "Levelized Cost of Energy Analysis – Version 10.0," December 2016 (see https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf).

Technology Type	Generation Technology Option	Representative Technology Option
Natural Gas	3x1 NGCC G/H-Class – DF	Combined-Cycle 3x1 MHI GAC - Fired
Natural Gas	3x1 NGCC J-Class	Combined-Cycle 3x1 MHI JAC
Natural Gas	3x1 NGCC J-Class – DF	Combined-Cycle 3x1 MHI JAC - Fired
Coal Fired	Subcritical Pulverized Coal	Subcritical Pulverized Coal
Coal Fired	Subcritical Pulverized Coal with Carbon Capture ("CC")	Subcritical Pulverized Coal with CC
Coal Fired	Circulating Fluidized Bed	Circulating Fluidized Bed
Coal Fired	Circulating Fluidized Bed with CC	Circulating Fluidized Bed with CC
Coal Fired	Supercritical Pulverized Coal – 500 MW	Supercritical Pulverized Coal
Coal Fired	Supercritical Pulverized Coal with CC – 425 MW	Supercritical Pulverized Coal with CC
Coal Fired	Supercritical Pulverized Coal – 750 MW	Supercritical Pulverized Coal
Coal Fired	Supercritical Pulverized Coal with CC – 638 MW	Supercritical Pulverized Coal with CC
Coal Fired	2x1 Integrated Gasification	2x1 Integrated Gasification
Coal Fired	2x1 Integrated Gasification with CC	2x1 Integrated Gasification with CC
Waste to Energy	Municipal Solid Waste Stoker Fired	MSW Stoker Fired
Waste to Energy	Refuse Derived Fuel Stoker Fired	RDF Stoker Fired
Waste to Energy	Wood Stoker Fired	Wood Stoker Fired
Waste to Energy	Landfill Gas Internal Combustion ("IC") Engine	Landfill Gas IC Engine
Waste to Energy	Anaerobic Digester Gas IC Engine	Anaerobic Digester Gas IC Engine
Waste to Energy	Co-fired Circulating Fluidized Bed	Co-fired Circulating Fluidized Bed
Waste to Energy	Co-fired Circulating Fluidized Bed	Co-fired Circulating Fluidized Bed
Energy Storage	Pumped Hydro Energy Storage	Pumped Hydro Energy Storage
Energy Storage	Adv. Battery Energy Storage (Lithium Ion)	Adv. Battery Energy Storage
Energy Storage	Compressed Air Energy Storage	Compressed Air Energy Storage
Renewable	Wind	Wind
Renewable	Solar Photovoltaic	Solar Photovoltaic
Renewable	Solar Thermal	Solar Thermal
Renewable	Hydro Electric	Hydro Electric
Nuclear	Small Modular Nuclear	Small Modular Nuclear

4.2.1.1 Natural Gas

Because of the EPA's New Source Performance Standards ("NSPS") for GHG, natural gas has become the fuel of choice for new fossil generation.

Typically, SCCTs are used for peaking power due to their fast load ramp rates and relatively low capital costs. The SCCT options include traditional frame machines as well as aero-derivative combustion turbines. Two options from General Electric ("GE") were evaluated as representative aero-derivative technology options: GE's LM6000 and LMS100 combustion turbines. Aero-derivative machines are flexible, more efficient than larger frame units, and can be installed with high temperature oxidation catalysts for carbon monoxide control and a selective catalytic reduction ("SCR") system for nitrogen oxides ("NO_x") control, which allows them to be located in areas with air emissions concerns. Frame simple-cycle machines, on the other hand, are larger and less expensive on $/kW basis. This study considered GE models 7EA and 7F-5 as representative technology options for the "E" and "F" turbine classes. The analysis considered building and operating single SCCT and multiple SCCT units to reflect savings from economies of scale.

Other natural gas-fired generation options include internal combustion engines, microturbines, and fuel cells. These options are easily scalable and well-suited for distributed generation and combined heat and power applications. For this reason, the supply-side analysis modeled these options as single units and as multiple units. The Wärtsilä 18V50DF reciprocating engine was evaluated in this study as the representative technology option for the reciprocating engine. Reciprocating engines can accommodate both natural gas and fuel oil, and have high efficiency across the ambient temperature range. Reciprocating engines are becoming popular as a means to follow wind turbine generation with their quick start times and operational flexibility. At present, fuel cells hold less promise for large utility-scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development.

Multiple NGCC configurations were evaluated: 1x1, 2x1, and 3x1 configurations based on "F-Class," "G/H-Class," and "J-Class" combustion turbines. The "F-Class" turbine designs tend to be smaller with faster startup times and higher operational flexibility, including peaking power capabilities and reduced load operation for off-peak turn-down. The "G/H-Class" turbine design is better geared for base load operation. Compared to the "F-Class", it is larger and more efficient, but with less turndown capability. The "J-Class" combustion turbine, which is an even larger and a more advanced design, is now commercially available in the United States, though no orders have been placed to date. The generation technology options table also includes DF, which is not a stand-alone resource option, but is considered to be an available option for any combined-cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency. DF is also a mechanism to recover lost power generation capability due to high ambient temperatures.

4.2.1.2 Coal Fired

The uncertainty of both proposed and future carbon regulations as well as the difficulty in obtaining environmental permits for coal-based generation have drastically reduced the interest in developing and investing in new pulverized coal technology. Supercritical pulverized coal ("PC") boilers continue to be the most efficient and cost effective with the smallest overall emission intensity rates among coal-fired technology options. Compared to subcritical PC, supercritical PC have better load following capability, faster ramp rates, and use less water.

The potential requirement for CO_2 capture ("CC") represents a significant cost for new and, possibly, existing coal resources. Existing federal NSPS for GHG regulations would require CC for new coal units to meet GHG emission limits. CC has been demonstrated in the field, but not at the scale that would be necessary for utility generation. As the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. In the meantime, however, early adopters may be subject to significant cost and performance risks.

Circulating fluidized bed ("CFB") boilers are a mature coal technology option that is well suited to burn fuels with a large variability in constituents. Large CFBs require more than one boiler. This increases capital costs but improves unit availability compared to PC technology options. Like PC technology options, CFB are also subject to NSPS for GHG regulations and would require the same CC technology.

The integrated gasification combined-cycle ("IGCC") is the third coal-based technology option considered in this study. A significant advantage for IGCC when compared to PC technology options is the fact that CO_2 capture with an IGCC is more proven for utility-scale applications. However, IGCC is a technology in continued development and various stages of commercialization. Only a limited number of IGCC plants have been built and operated around the world. These early plants have significantly exceeded their capital budgets.

4.2.1.3 Waste to Energy

Waste to energy ("WTE") generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Waste fuel is a very diverse category that includes: municipal solid waste ("MSW"), refuse derived fuel ("RDF"), wood chips, landfill gas, sewage, and tire derived fuel ("TDF"). Waste to energy fuels will be discussed in more detail in Section 4.3.3.2. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. The greatest challenge to building large WTE plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of WTE fuel poses a significant challenge, depending on the size of the facility.

4.2.1.4 Energy Storage

Energy storage technology options provide short term peaking generation and voltage frequency management. Battery energy storage systems have fast response times, allowing flexibility in load management. CAES and pumped hydro energy storage systems store off-peak power to be released during on-peak demand periods. Energy storage continues to be of interest since the variable nature of some conventional renewable generation alternatives could be enhanced if the energy produced could be stored. Land use requirements for pumped hydroelectric facilities make this storage technology option not very suitable in the Companies' territory. However, costs of battery energy storage technology options are decreasing, making energy storage a potentially viable option in scenarios with low load growth.

4.2.1.5 Renewables

The renewable options include solar, wind, and hydro generation. Due to the historically lower capital cost compared to other renewable options, wind turbines have been more common in the utility industry but do not provide a good source of capacity. The viability of wind generation is dependent on wind speeds. Kentucky has average wind speeds that are less than 12.5 mph. Wind speeds of 14.5 mph are needed for suitable wind generation. In this IRP, the peak contribution of the wind resources is assumed to be 16 percent of the total wind capacity. The assumed annual capacity factor of wind is 35 percent. A variable cost of $5.40/MWh (in 2013 dollars) was added to capture the cost of additional load-following resources needed to integrate wind into the system.[26]

Solar PV is a proven technology option for daytime peaking power and a viable option to pursue renewable goals and reduce emissions. Solar generation is a function of the amount of sunlight (i.e., electromagnetic radiation) incident on a surface per day, measured in kWh/m^2/day. Kentucky receives between 4 and 5.5 kWh/m^2/day. Areas in the western United States with high rates of solar development receive over 7.5 kWh/m^2/day. In this IRP, the peak contribution of the solar resource is assumed to be 66 percent of the total solar capacity.

The Companies recently finished upgrading the hydro units on Dix Dam and are in the process of upgrading the Ohio Falls Hydro units. The Companies are not aware of any viable alternatives near their service territories for expanding their portfolio of hydro generation.

[26] The wind integration cost was based on The National Renewable Energy Laboratory's Eastern Wind Integration and Transmission Study. For the complete report, see: http://www.nrel.gov/docs/fy11osti/47078.pdf.

The costs of renewable generation remain higher overall than fossil generation technology options. However, with tax incentives and RECs, both solar PV and wind technology options can be cost competitive in some circumstances.

4.2.1.6 Nuclear

Included in the generation technology option table is a small modular reactor ("SMR"). Currently, SMRs are considered conceptual in design and are developmental in nature. This emerging nuclear technology option offers a smaller footprint and standardized construction compared to traditional nuclear systems, which reduces overall project costs. However, sociopolitical resistance and regulatory obstacles will continue creating permitting challenges for nuclear.

4.2.2 Technology Option Inputs

Table 17 provides the operating characteristics and costs for each of the technology options considered in the screening analysis. The 2013 LGE-KU Generation Technology Assessment, conducted by Burns & McDonnell, served as the basis for these inputs. The 2013 LGE-KU Generation Technology Assessment report is also provided in Volume 3, Technical Appendix. Each of the key input assumptions are discussed in more detail in the following sections.

Table 17 – Generation Technology Options

Representative Technology Option	Operating Characteristics			Costs (2013 $)		
	Fuel Type	Capacity MW	Heat Rate Btu/kWh	Capital $/kW	FO&M $/kW-yr	VO&M $/MWh
Simple-cycle GE LM6000 – One Unit	Gas	49	[redacted]			
Simple-cycle GE LM6000 – Four Units	Gas	195				
Simple-cycle GE LMS100 – One Unit	Gas	106				
Simple-cycle GE LMS100 – Two Units	Gas	211				
Simple-cycle GE 7EA – One Unit	Gas	87				
Simple-cycle GE 7EA – Three Units	Gas	260				
Simple-cycle GE 7F-5 – One Unit	Gas	211				
Simple-cycle GE 7F-5 – Three Units	Gas	634				
Recip Engine - 100 MW – Six Units	Gas	100				
Recip Engine - 200 MW – Twelve Units	Gas	200				
Microturbine - 1 MW – Five Units	Gas	1				
Microturbine - 3 MW – Fifteen Units	Gas	3				
Fuel Cell - 10 MW – Four Units	Gas	11				
Fuel Cell - 30 MW – Twelve Units	Gas	34				
Combined-cycle 1x1 GE 7F-5	Gas	315				
Combined-cycle 1x1 GE 7F-5 - Fired	Gas	357				
Combined-cycle 1x1 MHI GAC	Gas	397				
Combined-cycle 1x1 MHI GAC - Fired	Gas	452				
Combined-cycle 1x1 MHI JAC	Gas	441				
Combined-cycle 1x1 MHI JAC - Fired	Gas	503				
Combined-cycle 2x1 GE 7F-5	Gas	638				
Combined-cycle 2x1 GE 7F-5 - Fired	Gas	719				
Combined-cycle 2x1 MHI GAC	Gas	796				
Combined-cycle 2x1 MHI GAC - Fired	Gas	901				
Combined-cycle 2x1 MHI JAC	Gas	884				
Combined-cycle 2x1 MHI JAC - Fired	Gas	1,003				
Combined-cycle 3x1 GE 7F-5	Gas	960				
Combined-cycle 3x1 GE 7F-5 - Fired	Gas	1,082				
Combined-cycle 3x1 MHI GAC	Gas	1,199				
Combined-cycle 3x1 MHI GAC - Fired	Gas	1,356				
Combined-cycle 3x1 MHI JAC	Gas	1,330				

Representative Technology Option	Operating Characteristics			Costs (2013 $)		
	Fuel Type	Capacity MW	Heat Rate Btu/kWh	Capital $/kW	FO&M $/kW-yr	VO&M $/MWh
Combined-cycle 3x1 MHI JAC - Fired	Gas	1,509				
Subcritical Pulverized Coal	Coal	500	[redacted]	[redacted]	[redacted]	[redacted]
Subcritical Pulverized Coal with CC	Coal	425	[redacted]	[redacted]	[redacted]	[redacted]
Circulating Fluidized Bed	Coal	500	[redacted]	[redacted]	[redacted]	[redacted]
Circulating Fluidized Bed with CC	Coal	425	[redacted]	[redacted]	[redacted]	[redacted]
Supercritical Pulverized Coal	Coal	500	[redacted]	[redacted]	[redacted]	[redacted]
Supercritical Pulverized Coal with CC	Coal	425	[redacted]	[redacted]	[redacted]	[redacted]
Supercritical Pulverized Coal	Coal	750	[redacted]	[redacted]	[redacted]	[redacted]
Supercritical Pulverized Coal with CC	Coal	638	[redacted]	[redacted]	[redacted]	[redacted]
2x1 Integrated Gasification	Coal	618	[redacted]	[redacted]	[redacted]	[redacted]
2x1 Integrated Gasification with CC	Coal	482	[redacted]	[redacted]	[redacted]	[redacted]
MSW Stoker Fired	MSW	50	[redacted]	[redacted]	[redacted]	[redacted]
RDF Stoker Fired	RDF	50	[redacted]	[redacted]	[redacted]	[redacted]
Wood Stoker Fired	Biomass	50	[redacted]	[redacted]	[redacted]	[redacted]
Landfill Gas IC Engine	LFG	5	[redacted]	[redacted]	[redacted]	[redacted]
Anaerobic Digester Gas IC Engine	Sewage	5	[redacted]	[redacted]	[redacted]	[redacted]
Co-fired Circulating Fluidized Bed	Coal/Biomass	50	[redacted]	[redacted]	[redacted]	[redacted]
Co-fired Circulating Fluidized Bed	Coal/TDF	50	[redacted]	[redacted]	[redacted]	[redacted]
Pumped Hydro Energy Storage	Charging	200	[redacted]	[redacted]	[redacted]	[redacted]
Adv. Battery Energy Storage (Lithium Ion)	Charging	20	[redacted]	[redacted]	[redacted]	[redacted]
Compressed Air Energy Storage	Gas/Charging	135	[redacted]	[redacted]	[redacted]	[redacted]
Wind	No Fuel	50	[redacted]	[redacted]	[redacted]	[redacted]
Solar Photovoltaic	No Fuel	50	[redacted]	[redacted]	[redacted]	[redacted]
Solar Thermal	No Fuel	50	[redacted]	[redacted]	[redacted]	[redacted]
Hydro Electric	No Fuel	50	[redacted]	[redacted]	[redacted]	[redacted]
Small Modular Nuclear	U235	225	[redacted]	[redacted]	[redacted]	[redacted]

4.2.2.1 Unit capacity

Unit capacity for each technology option is the net full load output in MW at annual average ambient conditions of 59°F and 60% relative humidity at 600 feet of elevation.

4.2.2.2 Heat rate

The heat rate value provided is the full load net heat rate (HHV Btu/kWh) under new and clean operating conditions. The heat rate is based on annual average performance.

4.2.2.3 Capital Cost

The following assumptions were used by Burns & McDonnell in developing the capital cost estimates for the generation technology options:

- All capital cost estimates are stated in 2013 "overnight" dollars.
- All generation technology options are based on a generic Greenfield site in Kentucky.
- Water, natural gas, and transmission are assumed to be available at the site boundary.
- Capital estimate include air quality control equipment based on expected Best Available Control Technologies ("BACT") requirements.
- Project indirect costs such as engineering and construction management as well as Engineering, Procurement, and Construction ("EPC") fees are included. Owner's costs such as project development and spare parts are also included.
- The following costs were excluded from the capital cost estimates: natural gas supply pipeline, sales and property tax, and transmission upgrades.

4.2.2.4 Fixed and variable O&M:
The following assumptions were used for determining the fixed and variable O&M costs:

- O&M costs are in 2013 dollars.
- O&M costs are based on operating a Greenfield site.
- Fixed O&M cost estimates include labor, office and administration, building and ground maintenance, communication, and laboratory expenses.
- Variable O&M costs include equipment maintenance, water treatment, ammonia, SCR replacements, and other consumables not including fuel.

4.2.2.5 Gas turbine major maintenance
Gas turbine maintenance was assumed to be covered by a long-term service agreement ("LTSA"). LTSA cost is based on $/operating hour if hours of operation exceed 30 hours per start. Otherwise, the cost is determined per combustion turbine start.

4.2.2.6 Emission Rates for SO_2, NO_x and CO_2
The emission rates provided for each technology option, when applicable, represent full load emission rates, expressed in lb/mmBtu. The emissions rates are based on expected BACT requirements.

4.2.3 Other Inputs

4.2.3.1 Investment Tax Credit and Renewable Energy Credits
The solar PV technology option was evaluated with a 10% investment tax credit.

As long as Kentucky does not have a renewable portfolio standard, the Companies would have the option to sell the RECs that are created when either a wind or solar facility produces electricity.[27] Based on the actual sales of RECs from the Companies' Brown Solar facility, the Companies assumed a $2.50 per REC price for both solar PV and wind in the supply-side screening analysis.

4.2.3.2 Financial Inputs
Table 18 provides the escalation rates used in the supply-side screening analysis for capital, fixed O&M, and variable O&M along with the revenue requirements discount rate.

Table 18 – Key Financial Inputs

Input	Value
Capital Escalation Rate	2.0%
Fixed O&M Escalation Rate	2.0%
Variable O&M Escalation Rate	2.0%
Revenue Requirements Discount Rate	6.48%

4.2.3.3 Fixed Charge Rates, Book Life and Tax Life Assumptions
Table 19 lists the fixed charge rate ("FCR"), book life and tax life for the main technology types. FCR is used to calculate a levelized cost of capital.

[27] One REC is created for every MWh that is produced.

Table 19 – FCR, Book Life and Tax Life

Technology Types	FCR (%)	Book Life (years)	Tax Life (Years)
Coal	8.50	50	20
SCCT	9.17	30	15
NGCC	8.87	40	20
Wind	8.65	25	5
Solar[28]	8.00	25	5
Hydro	8.57	55	20

4.2.3.4 SO_2 and NO_x Emission Prices

The emission price forecasts for SO_2 and NO_x in Table 20 are based on forecasts provided by IHS Energy.

[28] To appropriately account for the 10% investment tax credit, capital cost for the solar PV technology option was calculated using 8.00% FCR.

Table 20 – SO_2 and NO_x Emission Prices ($/short ton)

Year	Annual NO_x	Ozone NO_x	SO_2
2017	[redacted]		
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			
2046			

4.2.3.5 Firm Gas Transportation

Firm gas transportation costs for SCCT and NGCC technology options are listed in Table 21. Firm gas transportation is based on rates from Texas Gas for winter-no-notice and summer-no-notice service in the LG&E territory. Firm gas is assumed to be available for 16 hours of full load continuous operation for SCCT technology options and 24 hours of full load continuous operation for NGCC technology options.

Table 21 – Annual Firm Gas Transportation Cost

Representative Technology Option	Firm Gas Transportation (2013 $)
Simple-cycle GE LM6000 – One Unit	968,806
Simple-cycle GE LM6000 – Four Units	3,875,225
Simple-cycle GE LMS100 – One Unit	1,944,884
Simple-cycle GE LMS100 – Two Units	3,889,767
Simple-cycle GE 7EA – One Unit	2,071,370
Simple-cycle GE 7EA – Three Units	6,214,109
Simple-cycle GE 7F-5 – One Unit	4,363,915
Simple-cycle GE 7F-5 – Three Units	13,091,745
Recip Engine - 100 MW – Six Units	1,764,197
Recip Engine - 200 MW_– Twelve Units	3,528,394
Microturbine- 1 MW – Five Units	23,697
Microturbine - 3 MW – Fifteen Units	71,092
Fuel Cell - 10 MW – Four Units	281,126
Fuel Cell - 30 MW – Twelve Units	843,378
Combined-Cycle 1x1 GE 7F-5	6,494,371
Combined-Cycle 1x1 GE 7F-5 - Fired	7,686,258
Combined-Cycle 1x1 MHI GAC	8,079,095
Combined-Cycle 1x1 MHI GAC - Fired	9,571,025
Combined-Cycle 1x1 MHI JAC	8,527,388
Combined-Cycle 1x1 MHI JAC - Fired	10,120,189
Combined-Cycle 2x1 GE 7F-5	12,982,213
Combined-Cycle 2x1 GE 7F-5 - Fired	15,406,531
Combined-Cycle 2x1 MHI GAC	16,159,796
Combined-Cycle 2x1 MHI GAC - Fired	19,166,420
Combined-Cycle 2x1 MHI JAC	17,054,289
Combined-Cycle 2x1 MHI JAC - Fired	20,224,211
Combined-Cycle 3x1 GE 7F-5	19,464,926
Combined-Cycle 3x1 GE 7F-5 - Fired	23,095,539
Combined-Cycle 3x1 MHI GAC	24,221,944
Combined-Cycle 3x1 MHI GAC - Fired	28,725,838
Combined-Cycle 3x1 MHI JAC	25,594,972
Combined-Cycle 3x1 MHI JAC - Fired	30,339,018

4.3 Supply-Side Screening Key Uncertainties

In the screening analysis, the levelized cost for each of the technology options was calculated at various levels of utilization. In addition to the level of utilization (i.e., capacity factor), the levelized cost of each technology option is impacted by the uncertainty in capital cost, fuel cost, and the unit efficiency. As a result, the technology options were evaluated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, and ten capacity factors for a total of 270 cases. Each of these inputs is discussed in the following sections.

4.3.1 Capital Cost

Table 22 lists the capital cost uncertainty range by technology type. These capital cost ranges were used to develop high and low capital cost scenarios for each technology option. The uncertainty in capital cost for a given technology option is a function of the technology's maturity and the extent to which the cost of building a technology option is site-dependent. Generally, the more conventional or commercially mature technology options have a narrower capital cost range, whereas the more developmental or site-dependent technology options have a wider range.

Table 22– Capital Cost Range by Technology Type

Generation Technology Option	Capital Cost Range (%)	
	Low	High
Simple Cycle Combustion Turbine	-10%	20%
Combined Cycle Combustion Turbine	-10%	20%
Subcritical Pulverized Coal	-10%	25%
Subcritical Pulverized Coal with CC	-5%	35%
Circulating Fluidized Bed	-10%	25%
Circulating Fluidized Bed with CC	-5%	35%
Supercritical Pulverized Coal – 500 MW	-10%	25%
Supercritical Pulverized Coal with CC – 425 MW	-5%	35%
Supercritical Pulverized Coal – 750 MW	-10%	25%
Supercritical Pulverized Coal with CC – 638 MW	-5%	35%
2x1 Integrated Gasification	-10%	30%
2x1 Integrated Gasification with CC	-5%	35%
MSW Stoker Fired	-5%	10%
RDF Stoker Fired	-15%	15%
Wood Stoker Fired	-15%	15%
Landfill Gas IC Engine	-15%	15%
Anaerobic Digester Gas IC Engine	-15%	15%
Co-fired Circulating Fluidized Bed	-10%	20%
Co-fired Circulating Fluidized Bed	-10%	25%
Pumped Hydro Energy Storage	-10%	35%
Adv. Battery Energy Storage	-10%	25%
Compressed Air Energy Storage	-10%	35%
Wind	-10%	20%
Solar Photovoltaic	-20%	20%
Solar Thermal	-20%	20%
Hydro Electric	-15%	35%
Small Modular Nuclear	-5%	35%

4.3.2 Unit Efficiency (Heat Rate)

For non-renewable technology options, a technology option's levelized cost decreases as the assumed heat rate improves. In the screening analysis, each non-renewable technology option was evaluated at its expected heat rate and at heat rates 5% above and below the expected heat rate. A 5% decrease in heat rate represents technological advancement, whereas a 5% increase could represent degraded performance, actual unit efficiency falling short of design specification, or a decreased efficiency due to the addition of future environmental controls.

4.3.3 Fuel Prices

The levelized cost for non-renewable technology options was computed over three fuel price scenarios: Low, Mid, and High. The following sections discuss these scenarios for conventional and non-conventional fuels.

4.3.3.1 Natural Gas and Coal

As mentioned previously, natural gas has become the fuel of choice for new fossil generation. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. On the other hand, the impending nationwide retirement of coal units and the shift to NGCC units will increase the demand for natural gas and put upward pressure on prices. Additional upside price risk is associated with the possibility of regulations limiting the extraction of shale gas. The price of natural gas could have a significant impact on the Companies' optimal expansion plan; lower natural gas prices would favor natural gas technology options, while higher natural gas prices would make renewable generation more competitive. To address this long-term natural gas price uncertainty, the supply-side screening analysis considered three natural gas price scenarios.

The Henry Hub ("HH") natural gas price scenarios considered in this analysis are listed in Table 23. The Mid natural gas price forecast is based on market prices for the short term and the Energy Information Administration's ("EIA") 2016 Annual Energy Outlook ("AEO") for the long term. Prices in 2017 reflect NYMEX HH monthly forward prices as of 6/16/2016. Prices in 2018-2026 reflect a blend of forward market prices and the EIA's AEO 2016 No CPP Reference Case prices. Blending is 90% market in 2018 and declines in 10% increments to 10% market in 2026. Prices in 2027-2040 are the EIA's AEO 2016 No CPP Reference Case prices. Prices in 2041-2046 are escalated annually at the 2028-2038 CAGR of the EIA's forecast (2.1%) from the EIA's forecast price for 2040. Monthly prices after 2017 are calculated using average monthly shape indices derived from the market forwards for 2017-2022. The Low natural gas price forecast is based on EIA's 2016 AEO "High Oil and Gas Resource and Technology" scenario. To maintain a consistent spread between the Low and Mid natural gas price scenarios, the 2018 price in the Low scenario was interpolated between the 2017 and 2019 prices. The High natural gas price forecast is based on EIA's 2016 AEO "Low Oil and Gas Resource and Technology" scenario.

The Companies' forecasts for Illinois Basin high-sulfur ("ILB-HS") and Powder River Basin ("PRB") coals were blended to develop the delivered coal prices used in the analysis for a new coal unit and shown in Table 23. These prices reflect a blend of 75% ILB-HS and 25% PRB coals. Through 2021, these coal prices are based on (i) market bid prices and (ii) a forecast developed by Wood Mackenzie (an international management consultant company) in the spring of 2016.[29] In 2022-2040, these prices were escalated at the annual growth rates in the average coal price forecast from EIA's AEO 2016 No CPP Reference case. Beyond 2040, coal prices were extrapolated based on the price forecast's 2030-2040 CAGR. An average transportation cost adder is escalated throughout the forecast period.

[29] The coal prices in 2017 are based fully on the bid price curve. Prices in 2018 are 75% bid prices, 25% Wood Mackenzie. Prices in 2019 through 2021 are blended 50% bid prices and 50% Wood Mackenzie.

Table 23 – Natural Gas and Coal Prices (Nominal $/mmBtu)

Year	Henry Hub Natural Gas Prices Low	Henry Hub Natural Gas Prices Mid	Henry Hub Natural Gas Prices High	Coal Prices Blended (75% ILB-HS, 25% PRB)
2017	[redacted]			
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				
2045				
2046				

The level of natural gas prices determines the favorability of renewable technology options; as natural gas prices increase, the value of renewable technology options potentially increases. Furthermore, the relationship or "spread" between natural gas and coal prices is a key factor in comparing the value of existing or proposed natural gas alternatives to existing coal alternatives. With three natural gas price forecasts and one coal price forecast, this analysis considered three spreads between natural gas and coal prices. As a result, it was not necessary to develop more than one coal price forecast.

4.3.3.2 Non-Conventional Fuels

For the WTE generation technology options, both the fuel costs and fuel cost sensitivities are estimated based on research and data provided by EPRI and Burns & McDonnell. Table 24 lists the assumed price for non-conventional fuels in the Low, Mid, and High fuel price scenarios. These prices were assumed to escalate at 2.0% per year over the 30-year evaluation period. Each of these fuel types are discussed further in the following sections.

Table 24 – Non-Conventional Fuels (2013 Nominal $/mmBtu)

Fuel Type	Non-Conventional Delivered Fuel Prices Source (EPRI)		
	Low	Mid	High
Municipal Solid Waste	[redacted]		
Refuse Derived Fuel			
Biomass			
Landfill Gas			
Sewage			
Tire Derived Fuel			
Uranium (U-235)			

4.3.3.2.1 Municipal Solid Waste

The negative MSW price represents the tipping fee to accept and burn unprocessed solid waste in its as-discarded form with minimal processing. The tipping fee will be dependent on the availability of MSW landfills and their proximities to solid waste sources.

4.3.3.2.2 Refuse Derived Fuel

RDF is MSW that has been sorted to remove non-combustibles and then processed into pellets. The higher end range includes a quality product that has a clean air additive negating the need for more capital intensive equipment.

4.3.3.2.3 Biomass

Biomass refers to using plant-based fuels for energy production. The forecast developed for this analysis is based on wood chips supplied from a 50-mile radius of the plant. The price is highly dependent on the moisture content of the wood, availability in the area, as well as diesel prices.

4.3.3.2.4 Landfill Gas

LFG is a byproduct of the decomposition of waste stored in landfills. LFG is collected from wells at the landfill, filtered, and then compressed. The LFG forecast assumes that the generating unit will be located at the landfill site and the gas has a heating value of 600 Btu/ft^3. LFG prices vary greatly with the availability and quality of LFG.

4.3.3.2.5 Sewage

Bio-methane gas is produced from the digestion of sewage sludge or livestock manure. It is similar to LFG with respect to the quality of the fuel and the generation equipment required. The feedstock costs for most currently installed Anaerobic Digesters are zero.

4.3.3.2.6 Tire Derived Fuel

TDF consists of chipped tires with the steel belts removed. The co-firing of up to 10 percent of TDF (by weight) in a fluidized bed boiler can be considered a commercial technology option as there is no significant change in the technology for a dedicated coal unit. However, there is very limited success with mass firing of TDF. While TDF has a low ash and sulfur content as well as a fuel heating value equivalent to or better than coal, the general lack of availability of TDF is a drawback. TDF prices vary significantly with oil prices, the local tire market, and competitive buyers.

4.3.3.2.7 Uranium

The small modular nuclear reactor uses uranium enriched in the U-235 isotope for its fuel. Both the price and the range were provided by Burns & McDonnell.

4.3.3.2.8 Charging cost

The energy storage technology options must be charged or recharged by equipment utilizing electricity generated by another source. As such, charging is typically accomplished during periods of low demand by electricity with low generation costs. It is assumed that the energy storage options considered in this analysis are charged using power generated from the Companies' base load units such as coal and NGCC units. The uncertainty around charging costs depends on conventional fuel prices, actual load requirements, and the availability of base load units. Table 25 lists the charging costs used in the analysis.

Table 25 – Charging Cost ($/MWh)

Year	Charging Cost ($/MWh)		
	Low	Mid	High
2017	[redacted]		
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			
2046			

4.3.4 Capacity Factor

Where applicable, the levelized cost of each technology option was calculated over ten capacity factors (1% and 10-90% in 10% increments).

4.4 Supply-Side Screening Methodology

In the screening analysis, the Companies computed the 30-year levelized cost for the technology options developed by Burns & McDonnell over a range of scenarios. The levelized cost includes the costs associated with building and operating the unit. Where applicable, the following costs were considered in the analysis:

1. Fuel Costs
2. Maintenance Cost: Cost per Start, Hourly Operating Cost, or Cost per energy
3. Variable O&M

4. Capital Costs
5. Fixed O&M
6. Firm Gas Transportation Costs
7. Charging Cost
8. Emission Costs
9. Renewable Energy Credits

With some exceptions, the levelized cost of each technology option (in $/MWh) was calculated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, and ten capacity factors for a total of 270 cases.[30]

Several technology options were limited to a maximum capacity factor based on the operating characteristics of the technology option. Capacity factors for wind and solar were limited to 35% and 18%, respectively. The hydroelectric option was limited to a 42% capacity factor based on the Companies' experience with its current hydro assets.

Several technology options were not considered in the screening analysis.

- The 3x1 NGCC options were excluded from the analysis due to their size and impact on system reliability; given the relatively small size of the Companies' generating portfolio, recovering from the loss of such a large unit is difficult. While they were not excluded from the analysis, some larger 2x1 NGCC options create similar concerns.
- The "J-Class" combustion turbine was excluded from the analysis due to its nascent design and limited operating history; although it is now commercially available in the United States, no orders have been placed to date.
- The small modular nuclear reactor was also not included due to significant challenges in siting and permitting the unit.
- The MSW stoker fired technology option was excluded from the analysis due to the uncertainty regarding the availability and quality of municipal solid waste fuel.

All cases assumed REC market prices for wind and solar as well as a 10 percent investment tax credit for solar PV.

4.5 Supply-Side Screening Results

Table 26 lists the technology options that were ranked among the top four least-cost technology options for at least one of the 270 cases. A comparison of levelized costs for each technology is included in Section 5 – Appendix A.

---

[30] Each of these scenarios is discussed in Section 4.3.

Table 26 – Frequency of Occurrence of the Generation Technology Option in the Top Four

Generation Technology Option	# Occurrences				
	1st	2nd	3rd	4th	Total
2x1 NGCC G/H-Class – DF	0	23	117	129	**269**
2x1 NGCC G/H-Class	110	87	21	10	**228**
2x1 NGCC F-Class	0	82	76	20	**178**
Adv. Battery Energy Storage	58	33	43	30	**164**
SCCT F-Class – Three Units	52	9	5	5	**71**
2x1 NGCC F-Class – DF	0	0	0	68	**68**
Wind	38	3	1	3	**45**
SCCT F-Class – One Unit	0	24	7	1	**32**
Solar Photovoltaic	12	9	0	1	**22**
1x1 NGCC G/H-Class	0	0	0	3	**3**

The "2x1 NGCC G/H Class – DF" option ranked among the top four least-cost options in 269 of the 270 cases, and the "2x1 NGCC G/H-Class" option was least-cost in 110 cases and ranked among the top four least-cost options in 228 cases. The option to install three F-Class SCCTs ("SCCT F-Class – Three Units") was least-cost in 52 cases. The "2x1 NGCC G/H-Class" option was the best option for meeting intermediate and base load energy needs. The "SCCT F-Class – Three Units" option was the best option for meeting peak energy needs. The advanced battery energy storage, solar PV, and wind technology options were ranked among the top four least-cost technology options in multiple cases. Because these technologies are smaller and more scalable, they may be competitive in scenarios with low load growth.

Because the Companies do not have a capacity need over the 15-year planning horizon, the top generation technologies in Table 26 were not included a detailed expansion planning analysis.

5 Appendix A – Comparison of Levelized Costs from Supply-Side Screening at Varying Capacity Factors ("CF")[31]

Table 27 – Levelized Costs Comparison

Generation Technology Option	Capacity MW	Heat Rate Btu/kWh	Installed Cost $/kW	Fixed O&M $/kW-yr	Variable O&M $/MWh	Fixed Charge Rate %	Service Life Yrs	Levelized Cost ($/MWh)					
								CF 10%	CF 20%	CF 30%	CF 50%	CF 70%	CF 90%
Simple Cycle GE LM6000	49	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE LM6000_Add-on	195	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE LMS100	106	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE LMS100_Add-on	211	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE 7EA	87	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE 7EA_Add-on	260	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE 7F-5	211	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle GE 7F-5_Add-on	634	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Recip Engine - 100 MW	100	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Recip Engine - 100 MW_Add-on	200	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Microturbine - 1 MWM	1	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Microturbine - 1 MW_Add-on	3	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cell - 10 MW	11	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cell - 10 MW_Add-on	34	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 1x1 GE 7F-5	315	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 1x1 GE 7F-5 - Fired	357	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 1x1 MHI GAC	397	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 1x1 MHI GAC - Fired	452	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 2x1 GE 7F-5	638	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 2x1 GE 7F-5 - Fired	719	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 2x1 MHI GAC	796	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 2x1 MHI GAC - Fired	901	[redacted]	[redacted]	[redacted]	[redacted]	8.87%	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subcritical Pulverized Coal - w/Carbon Capture	425	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CirculatingFluidized Bed - w/Carbon Capture	425	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SupercriticalPulverized Coal - 500 MW - w/Carbon Capture	425	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SupercriticalPulverized Coal - 750 MW - w/Carbon Capture	638	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2x1 IntegratedGasification CC - w/Carbon Capture	482	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RDF Stoker Fired	50	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wood Stoker Fired	50	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Landfill GasIC Engine	5	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Anaerobic Digester Gas IC Engine	5	[redacted]	[redacted]	[redacted]	[redacted]	9.17%	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Co-fired Circulating Fluidized Bed_Coal/Biomass (50/50)	50	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Co-fired Circulating Fluidized Bed_Coal/TDF (90/10)	50	[redacted]	[redacted]	[redacted]	[redacted]	8.50%	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pumped HydroEnergy Storage	200	[redacted]	[redacted]	[redacted]	[redacted]	8.65%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adv. BatteryEnergy Storage	20	[redacted]	[redacted]	[redacted]	[redacted]	8.65%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CAES	135	[redacted]	[redacted]	[redacted]	[redacted]	8.65%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wind EnergyConversion	50	[redacted]	[redacted]	[redacted]	[redacted]	8.65%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SolarPhotovoltaic	50	[redacted]	[redacted]	[redacted]	[redacted]	8.00%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SolarThermal	50	[redacted]	[redacted]	[redacted]	[redacted]	8.65%	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HydroElectric	50	[redacted]	[redacted]	[redacted]	[redacted]	8.57%	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[31] Levelized costs are shown assuming Base capital costs, Base heat rates, and Mid natural gas prices.

6 Appendix B – Electric Sales & Demand Forecast Process

The Sales Analysis & Forecasting group develops the LG&E and KU sales and demand forecasts. These forecasts serve as foundational inputs for the Companies' generation forecast and business plan. This document summarizes the inputs to these forecasts as well as the forecast models.

6.1 Input Data

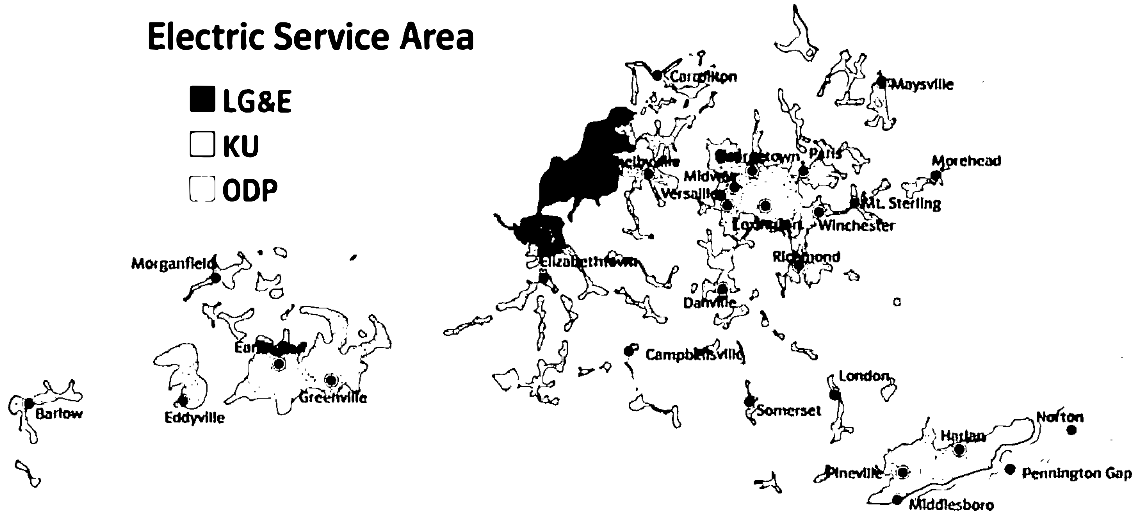
Table 28 provides a summary of data inputs.

Table 28 – Summary of Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	IHS Global Insight, Kentucky Data Center	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	IHS Global Insight	Annual or Quarterly – History and Forecast
Personal Income	IHS Global Insight	Annual by County
Weather	NOAA	Daily HDD/CDD Data by Weather Station – History
Bill Cycle Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Elasticities of Demand	EIA / Historical Trend	Annual – History
Billed Sales History	CCS Billing System	LG&E, KU and ODP – Monthly by Rate Group
Number of Customers History	CCS Billing System	LG&E, KU and ODP – Monthly by Rate Group

IHS Global Insight produces forecasts of macroeconomic drivers by county. With an understanding of the counties that make up each service territory, this data can be used to create service territory-specific forecasts of macroeconomic drivers. Figure 1 contains a map of the LG&E, KU, and ODP electric service territories.

Figure 1 – LG&E, KU, and ODP Service Territory Map



Two counties make up the majority of the LG&E service territory, while KU serves customers in parts of over 70 counties; ODP's service territory includes parts of five counties in southwestern Virginia. Service territory-specific macroeconomic forecasts are created by aggregating the applicable county-specific forecasts for the counties in LG&E, KU, and ODP service territories.

6.2 Energy Forecast Models

The Companies' energy forecast comprises multiple forecast models. All models forecast sales and the number of customers on a monthly basis. These forecasts are discussed in detail in the following sections.

6.2.1 Residential Forecast

The Residential forecast is comprised of three classes: KU Residential, LG&E Residential, and ODP Residential. The Residential forecast includes all customers on the Residential Service (RS) and Volunteer Fire Department (VFD) rate schedules. Residential sales are forecast for each company as the product of a customer forecast and a use-per-customer forecast.

6.2.1.1 Residential Customer Forecast

The number of residential customers is forecasted by company as a function of the number of forecasted households or forecasted population in the service territory. Household and population data by county and Metropolitan Statistical Area (MSA) is available from IHS Global Insight and the Kentucky Data Center.

6.2.1.2 Residential Use-per-Customer Forecast

Average use-per-customer is forecast using a Statistically-Adjusted End-Use (SAE) Model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

Use-per-Customer = a1*XHeat + a2*XCool + a3*XOther

The heating, cooling and other components (i.e., the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices.

Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer.

6.2.2 Commercial Forecast

The Commercial forecast comprises multiple rate class models: KU General Service, KU Large Commercial, KU All-Electric Schools, LG&E General Service, LG&E Primary Commercial, LG&E Secondary Commercial, ODP General Service, ODP Commercial, ODP Schools and ODP Municipal Pumping. Each of these rate classes is forecasted separately on a monthly basis over the forecast period. The period of historical data used in the models varies based on each rate class's history.

6.2.2.1 KU, LG&E, and ODP General Service

The general service forecasts include all customers on the General Service (GS) rate and comprise two separate forecasts: a sales forecast and a customer forecast. The former employs a Statistically-Adjusted End-Use model (SAE), which defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

The customer forecasts are a function of household or population growth since, historically, they are highly correlated.

6.2.2.2 KU Large Commercial

The KU Large Commercial forecast includes all customers on the PS Secondary and TOD Secondary rates. Sales to PS Secondary customers are modeled as a function of heating and cooling degree days, Retail and Wholesale Employment indices, and binary variables which account for anomalies in the historical data.

6.2.2.3 KU All-Electric Schools (AES)

The KU All-Electric Schools forecast includes all customers on the All-Electric School rate schedule. KU AES sales are modeled as a function of the number of KU households, weather, and binary variables to account for anomalies in the historical data.

6.2.2.4 LG&E Commercial

The LG&E Commercial forecast includes all customers on the CPS Primary, CPS Secondary, CTOD-Primary, and CTOD-Secondary rate schedules. The Primary and Secondary rates are forecasted separately to capture similar energy usage patterns and levels. LG&E Commercial sales are forecast in total as a function of weather, specific economic drivers, the number of customers, and other binary variables to account for anomalies in the historical data.

6.2.2.5 LG&E Special Contracts

The LG&E Special Contracts forecast includes Louisville Water Company and Fort Knox. These customers are forecasted individually, based on information and feedback from the customers and major account representatives.

6.2.2.6 ODP Commercial

The ODP Commercial forecast includes all customers on the PS Secondary and TOD Secondary rates. Sales to PS Secondary customers are modeled as a function of heating and cooling degree days, specific economic drivers, and binary variables which account for anomalies in the historical data.

6.2.2.7 ODP Schools

The ODP Schools forecast includes all customers on the School Service (SS) rate schedule. Sales to the ODP schools are modeled as a function of the number of households, weather, and binary variables.

6.2.2.8 ODP Municipal Pumping

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. ODP municipal pumping sales are forecasted using a trend model based on recent sales.

6.2.3 Lighting Forecast

The Lighting forecast comprises multiple rate classes: LG&E LES and TES, KU LES and TES, and unmetered Street Lighting for each company. All lighting-related energy is forecasted using a trend model based on recent sales.

6.2.4 Industrial Forecast

A relatively small number of customers in an industrial rate can make up a significant portion of the total sales for that rate. Furthermore, any expansion or reduction in operations by the larger industrial customers can significantly impact the Companies' load forecast. Therefore, the Companies work directly with the largest industrial customers (Major Accounts) to develop their forecasts. The large individually forecasted customers are removed from the historical energy sales data by rate, while the remaining customers are forecasted using econometric models described below. The total rate forecast is the combination of the individually forecasted customers and the customers forecasted using econometric models.

6.2.4.1 KU Industrial Forecast

The KU industrial forecast comprises three forecast models. The forecast models are aggregated by rate codes by voltage level.

6.2.4.1.1 Primary

The PS Primary, TOD Primary, and LTOD Primary rates are forecasted together, then allocated into individual rate forecasts using historical sales ratios. The Primary forecast includes all customers that take service at the primary distribution voltage. Sales to Primary customers are modeled as a function of an industry-weighted Industrial Production Index and weather.

6.2.4.1.2 Retail Transmission Service

The RTS forecast includes all retail customers previously on a Transmission-level rate. Since a large component is sales to Mine Power customers, the Wood-MacKenzie forecast of Eastern and Western Kentucky coal production is used as a driver. In recent years, the demand for lower sulfur eastern Kentucky coal has declined while the demand for higher sulfur western Kentucky coal has increased. Therefore, two mining forecasts are developed to more accurately reflect this trend. The two forecasts are combined to form the final KU RTS forecast.

6.2.4.1.3 Fluctuating Load Service

The FLS forecast includes one customer, the North American Stainless Arc Furnace. The FLS forecast is developed based on discussions with the customer.

6.2.4.2 LG&E Industrial Forecast

The LG&E industrial forecast consists of three forecast models: Industrial Primary (Power Service and Time of Day), Industrial Secondary (Power Service and Time of Day), and Retail Transmission Service. Each of these rate classes is forecasted separately with specific economic drivers and weather.

6.2.4.2.1 Industrial Primary (Power Service and Time of Day)

The Industrial Primary forecast includes all customers on Industrial Primary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

6.2.4.2.2 Industrial Secondary (Power Service and Time of Day)

The Industrial Secondary forecast includes all customers on Industrial secondary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

6.2.4.2.3 Retail Transmission Service

The RTS rate consists of both individually forecasted major accounts and smaller customers. The major accounts customer forecasts are developed with input from the major account managers and customer input. The remaining smaller customer forecasts are developed using a trend model based on recent sales.

6.2.4.3 ODP Industrial Forecast

The ODP industrial forecast is a combined forecast of PS Primary, TOD Primary, and RTS rates. Industrial sales are forecast as a function of the Eastern Kentucky Wood-Mackenzie index, number of customers, and weather.

6.2.5 KU Municipal Forecast

KU municipal forecasts are provided by various consultants for different cities. These forecasts are reviewed for consistency and compared to historical sales and trends. Questions or concerns regarding the forecasts are sent to the municipal customers and their consultants, if applicable. Any subsequent revisions received from the municipal customers are incorporated into the forecasts.

6.3 Hourly Demand Forecast

The hourly demand forecast is developed from the energy forecasts. The following steps are used to create the hourly demand forecast:

1. For each company and month, add an estimate for system losses to the sum of calendar sales to compute monthly calendar energy requirements.
2. For each company and for every month except the peak month (August), compute an average normalized load duration curve based on ten years of historical hourly energy requirements. For the peak month, the process is similar except the year with the lowest load factor and the years with the five highest load factors are excluded from the average. By focusing the average on some of the lower load factors, the resulting peak demand for each company (computed in step 3) will reflect a "summer" peak demand and not an average peak demand for the month of August. Because the summer peak could occur in any summer month, the average summer peak demand is higher than the average peak demand in August.
3. For each company and month, multiply each value in the normalized load duration curve by monthly energy requirements to produce hourly demands.
4. For each company and month, order the hourly demands chronologically based on load patterns in "reference months." The reference months (a) capture the calendar attributes of the forecast month in question (i.e., the pattern of weekdays and weekends over the month) and (b) maintain the historic relationship of (approximate) peak coincidence between the two companies.

For each month and hour, add the chronological load curves for LG&E and KU/ODP to produce an hourly energy requirements forecast for the combined companies.

Exhibit 4

Part 3

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
PJM Load Obligation (if appropriate)																		
1. Utility Peak Load (MW)																		
A. Summer																		
1. Base Forecast				7,137	7,183	6,935	6,912	6,897	6,907	6,912	6,924	6,925	6,926	6,918	6,947	6,968	6,986	6,995
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
4. Adjusted Load (1)	6,313	6,392	6,458	6,806	6,805	6,552	6,548	6,533	6,543	6,548	6,560	6,561	6,562	6,554	6,583	6,604	6,622	6,631
5. % Increase in Adjusted Load (from previous year)		1.2%	1.0%	5.4%	0.0%	-3.7%	-0.1%	-0.2%	0.2%	0.1%	0.2%	0.0%	0.0%	-0.1%	0.4%	0.3%	0.3%	0.1%
B. Winter (2)																		
1. Base Forecast				6,397	6,455	6,405	6,262	6,206	6,258	6,240	6,284	6,292	6,296	6,269	6,317	6,339	6,286	6,378
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	7,114	7,079	6,223	6,182	6,201	6,150	6,026	5,970	6,022	6,004	6,049	6,056	6,060	6,033	6,081	6,103	6,050	6,143
5. % Increase in Adjusted Load (from previous year)		-0.5%	-12.1%	-0.7%	0.3%	-0.8%	-2.0%	-0.9%	0.9%	-0.3%	0.7%	0.1%	0.1%	-0.4%	0.8%	0.4%	-0.9%	1.5%
2. Energy (GWh)																		
A. Base Forecast				35,907	35,978	35,095	34,578	34,593	34,601	34,629	34,699	34,720	34,739	34,774	34,877	34,983	35,084	35,148
B. Conservation, Efficiency				935	1,026	1,117	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109
C. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Adjusted Load	35,554	34,846	34,901	34,972	34,953	33,978	33,468	33,484	33,492	33,520	33,590	33,611	33,630	33,665	33,768	33,874	33,975	34,039
E. % Increase in Adjusted Load (from previous year)		-2.0%	0.2%	0.2%	-0.1%	-2.8%	-1.5%	0.0%	0.0%	0.1%	0.2%	0.1%	0.1%	0.1%	0.3%	0.3%	0.3%	0.2%

(1) Peak after energy efficiency and demand-side programs

(2) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015, etc.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
PJM Load Obligation (if appropriate)																		
1. Utility Peak Load (MW)																		
A. Summer																		
1. High Forecast				7,304	7,349	7,097	7,074	7,062	7,080	7,102	7,136	7,155	7,168	7,169	7,206	7,232	7,255	7,268
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
4. Adjusted Load (1)	6,313	6,392	6,458	6,972	6,971	6,714	6,710	6,698	6,716	6,738	6,772	6,791	6,803	6,805	6,842	6,868	6,891	6,904
5. % Increase in Adjusted Load		1.2%	1.0%	8.0%	0.0%	-3.7%	-0.1%	-0.2%	0.3%	0.3%	0.5%	0.3%	0.2%	0.0%	0.5%	0.4%	0.3%	0.2%
(from previous year)																		
B. Winter (2)																		
1. High Forecast				6,552	6,611	6,565	6,419	6,365	6,428	6,427	6,497	6,524	6,542	6,524	6,581	6,609	6,558	6,657
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	7,114	7,079	6,223	6,337	6,358	6,310	6,183	6,129	6,192	6,192	6,261	6,288	6,306	6,288	6,345	6,373	6,322	6,421
5. % Increase in Adjusted Load		-0.5%	-12.1%	1.8%	0.3%	-0.7%	-2.0%	-0.9%	1.0%	0.0%	1.1%	0.4%	0.3%	-0.3%	0.9%	0.4%	-0.8%	1.6%
(from previous year)																		
2. Energy (GWh)																		
A. High Forecast				36,770	36,841	35,952	35,422	35,453	35,511	35,629	35,818	35,937	36,024	36,111	36,254	36,391	36,516	36,600
B. Conservation, Efficiency				935	1,026	1,117	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109
C. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Adjusted Load	35,554	34,846	34,901	35,835	35,816	34,836	34,313	34,344	34,402	34,519	34,709	34,828	34,915	35,002	35,145	35,282	35,407	35,491
E. % Increase in Adjusted Load		-2.0%	0.2%	2.7%	-0.1%	-2.7%	-1.5%	0.1%	0.2%	0.3%	0.5%	0.3%	0.3%	0.2%	0.4%	0.4%	0.4%	0.2%
(from previous year)																		

(1) Peak after energy efficiency and demand-side programs

(2) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015, etc.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Load Obligation (if appropriate)																		
1. Utility Peak Load (MW)																		
A. Summer																		
1. Low Forecast				6,972	7,017	6,773	6,750	6,733	6,733	6,722	6,713	6,696	6,684	6,667	6,689	6,703	6,717	6,723
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
4. Adjusted Load (1)	6,313	6,392	6,458	6,640	6,639	6,390	6,385	6,369	6,369	6,358	6,348	6,332	6,320	6,303	6,325	6,339	6,353	6,359
5. % Increase in Adjusted Load (from previous year)		1.2%	1.0%	2.8%	0.0%	-3.8%	-0.1%	-0.3%	0.0%	-0.2%	-0.2%	-0.3%	-0.2%	-0.3%	0.3%	0.2%	0.2%	0.1%
B. Winter (2)																		
1. Low Forecast				6,242	6,299	6,244	6,105	6,047	6,088	6,052	6,072	6,059	6,050	6,013	6,053	6,069	6,014	6,100
2. Conservation, Efficiency				215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
3. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	7,114	7,079	6,223	6,026	6,045	5,990	5,869	5,811	5,852	5,816	5,836	5,824	5,814	5,777	5,817	5,833	5,778	5,864
5. % Increase in Adjusted Load (from previous year)		-0.5%	-12.1%	-3.2%	0.3%	-0.9%	-2.0%	-1.0%	0.7%	-0.6%	0.3%	-0.2%	-0.2%	-0.6%	0.7%	0.3%	-0.9%	1.5%
2. Energy (GWh)																		
A. Low Forecast				35,044	35,115	34,238	33,733	33,733	33,691	33,630	33,581	33,503	33,453	33,437	33,500	33,575	33,651	33,696
B. Conservation, Efficiency				935	1,026	1,117	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109
C. Demand-side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Adjusted Load	35,554	34,846	34,901	34,109	34,089	33,121	32,624	32,624	32,582	32,521	32,472	32,394	32,344	32,328	32,391	32,466	32,542	32,587
E. % Increase in Adjusted Load (from previous year)		-2.0%	0.2%	-2.3%	-0.1%	-2.8%	-1.5%	0.0%	-0.1%	-0.2%	-0.2%	-0.2%	-0.2%	0.0%	0.2%	0.2%	0.2%	0.1%

(1) Peak after energy efficiency and demand-side programs

(2) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015, etc.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: Mid Gas - Base Load	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	27,684	28,334	28,592	29,861	29,796	29,809	30,672	31,069	31,125	31,192	31,236	31,282	31,272	31,419	31,545
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	6,486	5,793	4,563	2,783	2,866	2,861	2,026	1,698	1,663	1,616	1,606	1,661	1,779	1,733	1,671
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	34,529	34,510	33,538	33,027	33,045	33,053	33,080	33,149	33,171	33,190	33,225	33,326	33,433	33,534	33,598
j. Purchased Power																		
1. Firm	896	837	921	442	442	438	440	438	438	438	440	438	438	439	440	439	439	439
2. Other	3,453	2,258	1,589	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,972	34,952	33,978	33,468	33,484	33,492	33,520	33,590	33,611	33,630	33,665	33,767	33,873	33,974	34,038
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: Mid Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	28,214	28,840	29,101	30,309	30,260	30,292	31,288	31,755	31,855	31,974	32,053	32,120	32,101	32,268	32,428
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	6,816	6,145	4,910	3,179	3,260	3,287	2,407	2,129	2,148	2,116	2,123	2,198	2,354	2,312	2,236
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	35,388	35,369	34,395	33,871	33,903	33,961	34,078	34,266	34,386	34,473	34,559	34,700	34,838	34,962	35,046
j. Purchased Power																		
1. Firm	896	837	921	444	444	439	440	439	439	439	440	439	439	440	441	440	440	440
2. Other	3,453	2,258	1,589	2	2	1	1	1	1	1	2	2	2	2	2	2	3	3
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	35,834	35,815	34,835	34,312	34,343	34,401	34,518	34,708	34,827	34,914	35,001	35,143	35,280	35,405	35,489
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: Mid Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	27,127	27,797	28,062	29,390	29,309	29,298	30,014	30,323	30,319	30,325	30,330	30,353	30,346	30,467	30,560
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	6,182	5,468	4,237	2,412	2,494	2,463	1,686	1,327	1,254	1,198	1,177	1,216	1,299	1,254	1,206
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	33,668	33,648	32,682	32,184	32,185	32,143	32,082	32,032	31,956	31,906	31,889	31,951	32,027	32,103	32,148
j. Purchased Power																		
1. Firm	896	837	921	440	440	438	439	438	438	438	439	438	438	438	439	438	438	438
2. Other	3,453	2,258	1,589	1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,109	34,089	33,121	32,624	32,624	32,582	32,521	32,472	32,394	32,344	32,328	32,391	32,466	32,542	32,587
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: High Gas - Base Load	(ACTUAL)			(PROJECTED)																	
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	30,700	31,335	31,420	31,226	31,291	31,171	31,431	31,416	31,285	31,285	31,338	31,417	31,465	31,665	31,806
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	3,469	2,791	1,735	1,415	1,368	1,496	1,261	1,343	1,494	1,513	1,488	1,507	1,550	1,438	1,352
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	34,529	34,509	33,538	33,024	33,041	33,049	33,075	33,142	33,161	33,180	33,209	33,307	33,397	33,486	33,540
j. Purchased Power																		
1. Firm	896	837	921	442	442	439	443	442	441	444	447	448	448	454	459	475	488	497
2. Other	3,453	2,258	1,589	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,972	34,952	33,978	33,468	33,484	33,492	33,520	33,590	33,611	33,630	33,665	33,767	33,873	33,974	34,038
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: High Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	31,138	31,774	31,935	31,777	31,853	31,747	32,101	32,152	32,045	32,084	32,176	32,281	32,330	32,560	32,734
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	3,891	3,212	2,077	1,706	1,662	1,826	1,586	1,720	1,943	1,989	1,975	2,006	2,070	1,948	1,845
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	35,388	35,369	34,394	33,866	33,898	33,956	34,069	34,255	34,370	34,456	34,534	34,670	34,783	34,891	34,961
j. Purchased Power																		
1. Firm	896	837	921	444	444	439	445	444	444	447	452	455	456	465	472	495	512	525
2. Other	3,453	2,258	1,589	2	2	1	1	1	1	1	2	2	2	2	2	2	3	3
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	35,834	35,815	34,835	34,312	34,343	34,401	34,518	34,708	34,827	34,914	35,001	35,143	35,280	35,405	35,489
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: High Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	30,239	30,862	30,866	30,638	30,689	30,551	30,711	30,619	30,449	30,400	30,411	30,461	30,500	30,665	30,772
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	3,070	2,403	1,433	1,161	1,111	1,208	985	1,026	1,118	1,117	1,086	1,096	1,122	1,025	956
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	33,668	33,648	32,682	32,182	32,183	32,141	32,079	32,028	31,950	31,900	31,880	31,939	32,005	32,072	32,111
j. Purchased Power																		
1. Firm	896	837	921	440	440	438	441	440	440	441	444	444	444	448	451	461	469	476
2. Other	3,453	2,258	1,589	1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,109	34,089	33,121	32,624	32,624	32,582	32,521	32,472	32,394	32,344	32,328	32,391	32,466	32,542	32,587
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: Low Gas - Base Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	26,699	27,310	28,382	28,174	27,516	26,555	27,646	27,475	28,030	28,027	28,491	28,738	29,055	29,210	29,215
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	7,455	6,817	4,773	4,471	5,146	6,115	5,051	5,292	4,759	4,781	4,351	4,206	3,996	3,942	4,001
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	34,513	34,510	33,538	33,027	33,045	33,053	33,081	33,149	33,171	33,190	33,225	33,326	33,433	33,534	33,598
j. Purchased Power																		
1. Firm	896	837	921	457	442	438	440	438	438	438	440	438	438	439	440	439	439	439
2. Other	3,453	2,258	1,589	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,972	34,952	33,978	33,468	33,484	33,492	33,520	33,590	33,611	33,630	33,665	33,767	33,873	33,974	34,038
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch2

GENERATION

Scenario: Low Gas - High Load	2014 (ACTUAL)	2015 (ACTUAL)	2016 (ACTUAL)	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	27,155	27,827	28,922	28,714	28,113	27,171	28,357	28,263	28,825	28,852	29,316	29,531	29,822	29,984	30,096
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	7,854	7,159	5,090	4,774	5,407	6,407	5,338	5,620	5,179	5,238	4,860	4,786	4,633	4,596	4,567
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	35,368	35,369	34,395	33,871	33,903	33,961	34,078	34,266	34,386	34,473	34,559	34,700	34,838	34,962	35,046
j. Purchased Power																		
1. Firm	896	837	921	464	444	439	440	439	439	439	440	439	439	440	441	440	440	440
2. Other	3,453	2,258	1,589	2	2	1	1	1	1	1	2	2	2	2	2	2	3	3
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	35,834	35,815	34,835	34,312	34,343	34,401	34,518	34,708	34,827	34,914	35,001	35,143	35,280	35,405	35,489
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch2

GENERATION

Scenario: Low Gas - Low Load	(ACTUAL)			(PROJECTED)																	
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. System Output (GWh)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	33,002	28,938	28,029	26,210	26,764	27,816	27,614	26,891	25,908	26,902	26,650	27,186	27,154	27,620	27,902	28,239	28,395	28,276
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	1,201	2,598	5,967	7,088	6,501	4,483	4,187	4,911	5,853	4,797	4,999	4,386	4,369	3,887	3,666	3,406	3,326	3,490
f. Hydro-Conventional	344	372	395	339	364	364	364	364	364	364	364	364	364	364	364	364	364	364
g. Hydro-Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable Resources	0	0	0	20	19	19	19	19	19	19	19	19	19	19	19	19	19	18
i. Total Generation (sum of a through h)	34,552	31,910	34,393	33,656	33,648	32,682	32,184	32,185	32,143	32,083	32,032	31,956	31,906	31,889	31,951	32,027	32,103	32,148
j. Purchased Power																		
1. Firm	896	837	921	452	440	438	439	438	438	438	439	438	438	438	439	438	438	438
2. Other	3,453	2,258	1,589	1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
k. Less Pumping Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Other Sales (1)	481	386	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
m. Total System Firm Energy Requirements	38,420	34,619	36,602	34,109	34,089	33,121	32,624	32,624	32,582	32,521	32,472	32,394	32,344	32,328	32,391	32,466	32,542	32,587
II. Energy Supplied by Competitive Service Providers	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

*In the event that a unit uses multiple fuels for generation (alternate fuel) allocate generation accordingly; igition and flame stabilizaiton fuels are not considered fuel for generation.

(1) To include all sales or delivery transactions with other electric utilities. (i.e., firm sales, diversity exchange, etc.)

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Mid Gas - Base Load	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	80%	82%	85%	90%	90%	90%	93%	94%	94%	94%	94%	94%	94%	94%	94%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	19%	17%	14%	8%	9%	9%	6%	5%	5%	5%	5%	5%	5%	5%	5%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	58%	58%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Mid Gas - High Load	(ACTUAL)			(PROJECTED)															
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	80%	82%	85%	89%	89%	89%	92%	93%	93%	93%	93%	93%	92%	92%	93%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	19%	17%	14%	9%	10%	10%	7%	6%	6%	6%	6%	6%	7%	7%	6%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	59%	59%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Mid Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	81%	83%	86%	91%	91%	91%	94%	95%	95%	95%	95%	95%	95%	95%	95%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	18%	16%	13%	7%	8%	8%	5%	4%	4%	4%	4%	4%	4%	4%	4%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	58%	58%	58%	58%	58%	58%	59%	58%	58%	58%	59%

170510006

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: High Gas - Base Load	**(ACTUAL)**			**(PROJECTED)**														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	89%	91%	94%	95%	95%	94%	95%	95%	94%	94%	94%	94%	94%	95%	95%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	10%	8%	5%	4%	4%	5%	4%	4%	5%	5%	4%	5%	5%	4%	4%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	58%	58%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: High Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	88%	90%	93%	94%	94%	93%	94%	94%	93%	93%	93%	93%	93%	93%	94%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	11%	9%	6%	5%	5%	5%	5%	5%	6%	6%	6%	6%	6%	6%	5%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	59%	59%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: High Gas - Low Load	**(ACTUAL)**			**(PROJECTED)**														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	90%	92%	94%	95%	95%	95%	96%	96%	95%	95%	95%	95%	95%	96%	96%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	9%	7%	4%	4%	3%	4%	3%	3%	3%	4%	3%	3%	4%	3%	3%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	58%	58%	58%	58%	58%	58%	59%	58%	58%	58%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Low Gas - Base Load	(ACTUAL)			(PROJECTED)															
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	77%	79%	85%	85%	83%	80%	84%	83%	85%	84%	86%	86%	87%	87%	87%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	22%	20%	14%	14%	16%	18%	15%	16%	14%	14%	13%	13%	12%	12%	12%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	58%	58%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Low Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	77%	79%	84%	85%	83%	80%	83%	82%	84%	84%	85%	85%	86%	86%	86%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	22%	20%	15%	14%	16%	19%	16%	16%	15%	15%	14%	14%	13%	13%	13%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	59%	58%	58%	59%	59%	59%	59%	59%	59%	59%	59%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch3

GENERATION

Scenario: Low Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
III. System Output Mix (%)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	96%	91%	81%	78%	80%	85%	86%	84%	81%	84%	83%	85%	85%	87%	87%	88%	88%	88%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	3%	8%	17%	21%	19%	14%	13%	15%	18%	15%	16%	14%	14%	12%	11%	11%	10%	11%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Hydro-Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable Resources	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
i. Total Generation (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
j. Purchased Power																		
1. Firm	2%	2%	3%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2. Other	9%	7%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
k. Less Pumping Energy.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
l. Less Other Sales (1)	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IV. SYSTEM LOAD FACTOR	64%	62%	62%	59%	59%	59%	58%	58%	58%	58%	58%	58%	58%	59%	58%	58%	58%	59%

*In the event that a unit uses multiple fuels for generation (alternate fuel) allocate generation accordingly; igition and flame stabilizaiton fuels are not considered fuel for generation.

(1) To include all sales or delivery transactions with other electric utilities. (i.e., firm sales, diversity exchange, etc.)

(a-i) percentage of total generation

(j-l) percentage of energy requirements

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch4

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
I. Capability (MW)																		
1. Summer																		
a. Installed Net Dependable Capability (1)	7,915	7,823	7,837	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841	7,841
b. Total Positive Interchange commitments (2)	152	317	317	317	317	152	152	152	152	152	152	152	152	152	152	152	152	152
c. Capability in Cold Reserve/ Reserve Shutdown Status (1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Demand-side and Response (4)	145	136	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
e. Total Net Summer Capabilty (a+b+c+d)	8,212	8,276	8,284	8,288	8,288	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123	8,123
2. Winter (3)																		
a. Installed Net Dependable Capability (1)	8,187	8,146	8,146	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120
b. Total Positive Interchange commitments (2)	158	158	323	323	323	323	158	158	158	158	158	158	158	158	158	158	158	158
c. Capability in Cold Reserve/ Reserve Shutdown Status (1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Demand-side and Response (4)	145	136	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
e. Total Net Winter Capabilty (a+b+c+d)	8,490	8,440	8,599	8,573	8,573	8,573	8,408	8,408	8,408	8,408	8,408	8,408	8,408	8,408	8,408	8,408	8,408	8,408

(1) Provide Net Seasonal Capability

(2) To include firm commitments for the receipt of specified blocks of power (i.e. unit power, limited term, diversity exchange, cogeneration, small power production, etc.)

(3) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015, etc.

(4) Reflects expected peak impact of Curtailable Service Rider customers. All other DSM demand response and energy efficiency included in Adjusted Load - see Sch 1

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch5

POWER SUPPLY DATA (cont.)

	(ACTUAL)			(PROJECTED)														
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
II. Load (MW)																		
1. Summer																		
a. Adjusted Summer Peak (1)	6,313	6,392	6,458	6,806	6,805	6,552	6,548	6,533	6,543	6,548	6,560	6,561	6,562	6,554	6,583	6,604	6,622	6,631
b. Total Negative Power Commitments (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. Total Summer Peak	6,313	6,392	6,458	6,806	6,805	6,552	6,548	6,533	6,543	6,548	6,560	6,561	6,562	6,554	6,583	6,604	6,622	6,631
d. Percent Increase in Total Summer Peak		1.2%	1.0%	5.4%	0.0%	-3.7%	-0.1%	-0.2%	0.2%	0.1%	0.2%	0.0%	0.0%	-0.1%	0.4%	0.3%	0.3%	0.1%
2. Winter (3)																		
a. Adjusted Winter Peak (1)	7,114	7,079	6,223	6,182	6,201	6,150	6,026	5,970	6,022	6,004	6,049	6,056	6,060	6,033	6,081	6,103	6,050	6,143
b. Total Negative Power Commitments (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. Total Winter Peak (4)	7,114	7,079	6,223	6,182	6,201	6,150	6,026	5,970	6,022	6,004	6,049	6,056	6,060	6,033	6,081	6,103	6,050	6,143
d. Percent Increase in Total Winter Peak		-0.5%	-12.1%	-0.7%	0.3%	-0.8%	-2.0%	-0.9%	0.9%	-0.3%	0.7%	0.1%	0.1%	-0.4%	0.8%	0.4%	-0.9%	1.5%

(1) Peak after energy efficiency and demand-side programs, see page 1.

(2) To include firm comminments for the delivery of specified blocks of power (i.e. unit power, limited term, diversity exchange. etc.)

(3) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015, etc.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company

Sch6

POWER SUPPLY DATA (continued)

Scenario: Base Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Reserve Margin																		
(Including Cold Reserve Capability) (1)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,482	1,483	1,571	1,575	1,590	1,580	1,575	1,563	1,562	1,561	1,569	1,540	1,519	1,501	1,492
b. Percent of Load	28%	28%	28%	22%	22%	24%	24%	24%	24%	24%	24%	24%	24%	24%	23%	23%	23%	23%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,391	2,371	2,423	2,382	2,437	2,386	2,404	2,359	2,352	2,348	2,375	2,326	2,305	2,357	2,265
b. Percent of Load	18%	18%	38%	39%	38%	39%	40%	41%	40%	40%	39%	39%	39%	39%	38%	38%	39%	37%
II. Reserve Margin																		
(Excluding Cold Reserve Capability) (3)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,482	1,483	1,571	1,575	1,590	1,580	1,575	1,563	1,562	1,561	1,569	1,540	1,519	1,501	1,492
b. Percent of Load	28%	28%	28%	22%	22%	24%	24%	24%	24%	24%	24%	24%	24%	24%	23%	23%	23%	23%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,391	2,371	2,423	2,382	2,437	2,386	2,404	2,359	2,352	2,348	2,375	2,326	2,305	2,357	2,265
b. Percent of Load	18%	18%	38%	39%	38%	39%	40%	41%	40%	40%	39%	39%	39%	39%	38%	38%	39%	37%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch6

POWER SUPPLY DATA (continued)

Scenario: High Load	(ACTUAL)			(PROJECTED)															
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Reserve Margin																		
(Including Cold Reserve Capability) (1)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,316	1,317	1,409	1,413	1,426	1,407	1,385	1,352	1,332	1,320	1,318	1,282	1,255	1,232	1,219
b. Percent of Load	28%	28%	28%	19%	19%	21%	21%	21%	21%	21%	20%	20%	19%	19%	19%	18%	18%	18%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,236	2,215	2,263	2,225	2,278	2,216	2,216	2,147	2,120	2,102	2,119	2,063	2,035	2,086	1,987
b. Percent of Load	18%	18%	38%	35%	35%	36%	36%	37%	36%	36%	34%	34%	33%	34%	33%	32%	33%	31%
II. Reserve Margin																		
(Excluding Cold Reserve Capability) (3)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,316	1,317	1,409	1,413	1,426	1,407	1,385	1,352	1,332	1,320	1,318	1,282	1,255	1,232	1,219
b. Percent of Load	28%	28%	28%	19%	19%	21%	21%	21%	21%	21%	20%	20%	19%	19%	19%	18%	18%	18%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,236	2,215	2,263	2,225	2,278	2,216	2,216	2,147	2,120	2,102	2,119	2,063	2,035	2,086	1,987
b. Percent of Load	18%	18%	38%	35%	35%	36%	36%	37%	36%	36%	34%	34%	33%	34%	33%	32%	33%	31%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch6

POWER SUPPLY DATA (continued)

Scenario: Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Reserve Margin																		
(Including Cold Reserve Capability) (1)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,648	1,649	1,733	1,738	1,754	1,754	1,765	1,775	1,791	1,804	1,820	1,798	1,784	1,770	1,765
b. Percent of Load	28%	28%	28%	25%	25%	27%	27%	28%	28%	28%	28%	28%	29%	29%	28%	28%	28%	28%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,546	2,528	2,583	2,539	2,596	2,556	2,591	2,571	2,584	2,594	2,630	2,590	2,574	2,629	2,543
b. Percent of Load	18%	18%	38%	42%	42%	43%	43%	45%	44%	45%	44%	44%	45%	46%	45%	44%	46%	43%
II. Reserve Margin																		
(Excluding Cold Reserve Capability) (3)																		
1. Summer Reserve Margin																		
a. MW	1,777	1,797	1,826	1,648	1,649	1,733	1,738	1,754	1,754	1,765	1,775	1,791	1,804	1,820	1,798	1,784	1,770	1,765
b. Percent of Load	28%	28%	28%	25%	25%	27%	27%	28%	28%	28%	28%	28%	29%	29%	28%	28%	28%	28%
2. Winter Reserve Margin (2)																		
a. MW	1,252	1,245	2,376	2,546	2,528	2,583	2,539	2,596	2,556	2,591	2,571	2,584	2,594	2,630	2,590	2,574	2,629	2,543
b. Percent of Load	18%	18%	38%	42%	42%	43%	43%	45%	44%	45%	44%	44%	45%	46%	45%	44%	46%	43%

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch6

POWER SUPPLY DATA (continued)

III. Annual Loss-of-Load Hours

	(ACTUAL)			(PROJECTED)														
Scenario:	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Mid Gas - Base Load		Not Applicable		2	3	2	2	2	2	2	2	2	2	2	3	3	3	3
Mid Gas - High Load		Not Applicable		5	5	4	3	3	3	4	4	5	5	6	7	8	8	9
Mid Gas - Low Load		Not Applicable		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
High Gas - Base Load		Not Applicable		2	3	2	2	2	2	2	2	2	2	2	3	3	3	3
High Gas - High Load		Not Applicable		5	5	4	3	3	3	4	4	5	5	6	7	8	8	9
High Gas - Low Load		Not Applicable		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Low Gas - Base Load		Not Applicable		2	3	2	2	2	2	2	2	2	2	2	3	3	3	3
Low Gas - High Load		Not Applicable		5	5	4	3	3	3	4	4	5	5	6	7	8	8	9
Low Gas - Low Load		Not Applicable		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

(1) To be calculated based on Total Net Capability for summer and winter.

(2) 2014 data refers to winter of 2013/2014, 2015 data refers to winter of 2014/2015 etc.

(3) Same as footnote 1 above less capability in cold reserve.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch7

Capacity Data

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Installed Capacity (MW) (1)																		
a. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Coal	5,894	5,150	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134
c. Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas	2,085	2,901	2,921	2,921	2,921	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
f. Hydro-Conventional	88	90	92	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
g. Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Renewable	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
i. Total (sum of a through h)	8,067	8,140	8,154	8,158	8,158	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993	7,993
II. Installed Capacity Mix (%) (2)																		
a. Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
b. Coal	73%	63%	63%	63%	63%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%
c. Heavy Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
d. Light Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
e. Natural Gas	26%	36%	36%	36%	36%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
f. Hydro-Conventional	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
g. Pumped Storage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
h. Renewable	0%	0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
i. Total (sum of a through h)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

(1) Not dependable installed generation capability during peak season; unit capabilities to be classified by primary fuel type; for winter peaking utilities-2014 refers to the winter of 2014/2015 etc.

(2) Each item in Section I as a percent of line i (total)

Kentucky Utilities Company and Louisville Gas and Electric Company — **Sch8**

UNIT PERFORMANCE DATA (1)

Equivalent Availability Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Brown 1	91.1	72.5	89.0	89.4	85.9	89.4	85.9	89.4	77.2	89.4	85.9	89.4	85.9	89.4	85.9	77.2	85.9	89.4
Brown 2	84.3	95.4	87.0	87.7	77.2	89.4	87.7	89.4	87.7	89.4	87.7	77.2	87.7	89.4	87.7	89.4	87.7	89.4
Brown 3	80.2	76.3	78.8	86.8	86.8	86.8	77.9	90.3	86.8	90.3	86.8	90.3	86.8	77.9	86.8	90.3	86.8	90.3
Brown 5	96.8	88.3	93.7	76.2	90.1	90.1	88.4	90.1	90.1	90.1	90.1	90.1	90.1	90.1	90.1	90.1	90.1	90.1
Brown 6	94.6	97.7	97.7	88.4	76.2	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	90.1	90.1	90.1	90.1	90.1
Brown 7	95.0	98.2	97.3	88.4	88.4	88.4	76.2	88.4	88.4	88.4	88.4	88.4	88.4	90.1	90.1	90.1	90.1	90.1
Brown 8	96.3	91.4	95.0	86.6	90.1	90.1	76.2	90.1	90.1	90.1	88.4	90.1	90.1	90.1	90.1	90.1	90.1	90.1
Brown 9	93.9	91.5	93.9	86.6	90.1	90.1	88.4	90.1	90.1	90.1	76.2	90.1	90.1	90.1	90.1	90.1	90.1	90.1
Brown 10	94.7	80.1	98.0	86.6	90.1	90.1	90.1	88.4	90.1	90.1	90.1	90.1	76.2	90.1	90.1	90.1	90.1	90.1
Brown 11	95.8	91.4	96.4	86.6	76.2	90.1	90.1	90.1	90.1	88.4	90.1	90.1	90.1	90.1	90.1	90.1	90.1	90.1
Cane Run 4	86.1	77.7	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	87.7	79.4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	71.3	57.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	85.8	86.9	85.8	87.6	82.3	87.6	87.6	87.6	77.1	87.6	85.8	87.6	82.3	87.6	85.8	87.6	77.1
Cane Run 11	99.6	93.3	94.8	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Ghent 1	89.6	74.6	89.0	86.8	85.0	86.8	85.0	85.0	77.9	86.8	86.8	85.0	86.8	86.8	86.8	77.9	86.8	86.8
Ghent 2	92.9	78.4	90.7	85.0	86.8	77.9	85.0	85.0	86.8	86.8	86.8	86.8	77.9	86.8	86.8	86.8	86.8	86.8
Ghent 3	80.5	84.7	85.8	86.8	77.9	85.0	86.8	86.8	86.8	85.0	85.0	77.9	86.8	86.8	86.8	86.8	86.8	86.8
Ghent 4	78.1	94.6	88.4	86.8	85.0	85.0	85.0	77.9	85.0	86.8	85.0	86.8	85.0	86.8	77.9	86.8	86.8	86.8
G. River 3	91.2	88.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
G. River 4	88.3	84.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	98.2	99.8	99.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Mill Creek 1	90.1	77.3	92.6	85.0	90.3	77.9	90.3	85.0	90.3	85.0	90.3	85.0	90.3	85.0	90.3	77.9	90.3	85.0
Mill Creek 2	80.7	76.7	87.2	86.8	77.9	90.3	85.0	90.3	85.0	90.3	85.0	90.3	85.0	90.3	77.9	90.3	85.0	90.3
Mill Creek 3	91.8	85.4	75.4	83.2	90.3	77.9	90.3	85.0	90.3	85.0	90.3	85.0	90.3	77.9	90.3	85.0	90.3	85.0
Mill Creek 4	66.3	89.4	83.4	90.3	77.9	90.3	85.0	90.3	77.9	90.3	85.0	90.3	85.0	90.3	85.0	90.3	77.9	90.3
Paddy's Run 11&12 (3)	96.6	76.8	79.2	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Paddy's Run 13	90.6	84.7	76.6	88.4	88.4	88.4	88.4	60.6	55.4	88.4	88.4	88.4	88.4	90.1	90.1	90.1	90.1	90.1
Trimble 1 75%	93.2	77.3	94.9	75.1	89.4	84.1	89.4	84.1	89.4	84.1	89.4	76.9	89.4	84.1	89.4	84.1	89.4	84.1
Trimble 2 75%	60.1	85.4	65.6	79.1	73.9	80.8	80.8	80.8	80.8	80.8	80.8	80.8	73.9	80.8	80.8	80.8	80.8	80.8
Trimble 5	98.6	92.9	93.8	83.4	92.5	92.5	92.5	92.5	79.8	92.5	92.5	92.5	92.5	94.3	94.3	94.3	94.3	94.3
Trimble 6	97.5	93.3	81.2	92.5	92.5	92.5	92.5	92.5	92.5	92.5	79.8	92.5	92.5	94.3	94.3	94.3	94.3	94.3
Trimble 7	97.2	94.2	97.1	92.5	83.4	92.5	92.5	92.5	92.5	92.5	92.5	79.8	92.5	94.3	94.3	94.3	94.3	94.3
Trimble 8	96.6	96.4	97.0	92.5	90.7	92.5	92.5	92.5	92.5	83.4	92.5	92.5	92.5	94.3	94.3	94.3	94.3	94.3
Trimble 9	95.7	95.8	84.1	92.5	92.5	83.4	92.5	92.5	92.5	92.5	92.5	79.8	92.5	94.3	94.3	94.3	94.3	94.3
Trimble 10	97.8	97.3	97.3	92.5	92.5	90.7	92.5	92.5	92.5	92.5	92.5	92.5	83.4	94.3	94.3	94.3	94.3	94.3
Zorn 1	85.0	81.3	80.8	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0

(1) Combustion turbines to be reported as a composite facilty.

(2) Haefling 1-2 actuals include Haefling 3

(3) Paddy's Run 11 & 12 each have a 50% Projected EAF.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Base Load																		
E.W. Brown 1	40.0	22.3	23.4	3.5	9.3	12.8	11.9	14.4	7.4	19.0	25.2	34.3	34.1	33.4	33.4	29.6	33.5	34.7
E.W. Brown 2	51.8	42.7	27.8	12.1	16.8	20.3	14.3	16.5	15.6	23.2	30.0	31.3	36.6	36.1	35.8	37.7	35.5	35.6
E.W. Brown 3	42.1	33.5	30.4	7.5	14.7	15.6	8.9	11.4	12.8	18.5	20.8	29.1	28.5	22.9	25.8	26.9	23.4	23.9
E.W. Brown 5	3.5	10.8	3.7	1.0	1.2	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
E.W. Brown 6	13.7	16.2	1.8	2.7	2.4	1.4	1.0	1.0	1.2	1.0	0.9	1.1	1.0	1.1	1.1	1.1	1.1	1.2
E.W. Brown 7	16.3	12.5	1.8	3.4	3.1	1.5	1.1	1.1	1.2	1.1	1.1	1.2	1.1	1.2	1.2	1.2	1.2	1.3
E.W. Brown 8	2.2	7.3	9.5	0.8	0.9	0.6	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
E.W. Brown 9	1.6	8.4	10.4	0.6	0.6	0.3	0.3	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
E.W. Brown 10	1.8	7.8	10.4	0.4	0.5	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
E.W. Brown 11	2.2	5.4	5.8	0.6	0.7	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	84.9	78.0	64.7	38.1	39.9	39.1	26.3	21.4	19.9	19.3	18.6	19.9	21.5	21.1	19.4
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ghent 1	77.5	60.9	72.9	78.2	77.5	80.4	81.6	80.6	74.4	82.6	82.9	80.4	82.5	82.2	82.8	73.8	82.5	82.0
Ghent 2	77.7	58.8	68.3	75.4	77.9	70.2	77.8	77.6	78.0	78.3	78.9	80.2	72.5	80.2	81.1	81.1	81.0	80.7
Ghent 3	71.7	71.1	63.0	45.3	49.4	49.6	58.4	59.5	60.4	58.1	57.4	55.3	61.9	60.2	60.7	62.2	61.2	61.1
Ghent 4	70.9	80.3	71.9	69.9	69.1	68.6	75.2	69.4	77.9	77.0	75.0	78.0	77.5	78.6	69.2	79.7	79.1	78.3
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	73.7	79.7	68.8	80.1	76.9	82.6	77.6	83.4	79.2	84.6	78.9	83.9	72.3	84.5	79.0
Mill Creek 2	66.6	55.6	63.4	65.1	62.0	78.1	73.7	81.6	77.9	83.3	79.0	84.4	80.1	85.1	73.4	85.5	80.6	85.5
Mill Creek 3	78.0	63.6	58.0	77.5	85.5	72.1	83.0	80.4	86.9	81.3	86.5	81.8	86.9	74.7	86.4	81.5	86.4	81.2
Mill Creek 4	55.6	67.8	57.9	89.7	77.6	90.5	85.4	90.7	78.3	90.8	85.4	90.7	85.4	90.8	85.4	90.8	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Paddy's Run 13	8.1	14.1	6.3	24.4	22.8	15.7	10.5	8.3	7.7	7.0	6.4	7.6	7.4	7.7	7.3	7.7	7.2	7.7
Trimble County 1 (75%)	80.0	64.4	79.5	65.2	79.2	73.3	78.7	74.2	78.7	74.9	79.6	69.2	80.2	74.9	79.9	75.7	80.1	75.0
Trimble County 2 (75%)	59	84	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	20.5	18.1	12.3	8.8	9.1	8.1	8.3	6.9	7.9	7.8	8.1	7.8	8.2	7.7	8.3
Trimble County 6	10.4	13.8	5.6	18.5	14.2	9.2	6.5	6.7	8.1	6.2	4.7	6.1	5.9	6.2	5.9	6.3	5.9	6.4
Trimble County 7	7.7	16.4	11.5	14.9	9.2	6.8	4.7	5.0	6.1	4.6	4.4	4.2	4.5	4.8	4.6	4.8	4.6	5.0
Trimble County 8	2.9	5.0	2.9	11.5	8.5	4.9	3.4	3.6	4.5	3.0	3.3	3.7	3.4	3.5	3.3	3.5	3.4	3.7
Trimble County 9	9.0	17.5	11.3	9.0	6.9	3.4	2.6	2.5	3.2	2.5	2.4	2.3	2.4	2.6	2.5	2.6	2.5	2.7
Trimble County 10	3.7	4.6	10.0	6.9	5.0	2.5	1.9	1.8	2.2	1.8	1.7	2.0	1.7	1.9	1.8	1.9	1.9	2.0
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Scenario: Mid Gas - High Load																			
E.W. Brown 1	40.0	22.3	23.4	4.3	10.9	14.9	13.9	16.9	9.1	22.5	29.3	39.5	39.8	39.5	39.3	35.1	39.6	41.2	
E.W. Brown 2	51.8	42.7	27.8	13.8	18.9	22.8	16.6	19.1	18.2	26.7	34.0	35.5	41.8	41.8	41.3	43.6	41.2	41.5	
E.W. Brown 3	42.1	33.5	30.4	9.0	16.8	18.0	10.5	13.6	15.3	22.1	24.6	34.2	33.8	27.7	31.1	32.4	28.7	29.5	
E.W. Brown 5	3.5	10.8	3.7	1.4	1.7	1.0	0.7	0.7	0.8	0.7	0.7	0.9	0.8	0.9	0.9	1.0	1.0	1.1	
E.W. Brown 6	13.7	16.2	1.8	3.5	3.3	2.0	1.4	1.4	1.7	1.4	1.5	1.8	1.7	1.8	1.8	1.9	1.9	2.0	
E.W. Brown 7	16.3	12.5	1.8	4.5	4.0	2.1	1.4	1.5	1.8	1.6	1.6	1.9	1.8	1.9	1.9	2.0	2.0	2.1	
E.W. Brown 8	2.2	7.3	9.5	1.2	1.2	0.9	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	
E.W. Brown 9	1.6	8.4	10.4	0.8	0.9	0.5	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6	
E.W. Brown 10	1.8	7.8	10.4	0.6	0.7	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	
E.W. Brown 11	2.2	5.4	5.8	0.9	1.0	0.6	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Cane Run 7	NA	19.7	76.8	85.5	79.4	67.0	42.2	44.1	43.4	30.0	25.9	24.6	24.1	23.5	25.1	27.1	26.9	24.7	
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Ghent 1	77.5	60.9	72.9	79.2	78.4	81.3	82.2	81.3	75.1	83.5	83.8	81.4	83.5	83.3	83.8	74.8	83.6	83.3	
Ghent 2	77.7	58.8	68.3	76.1	78.5	70.6	78.2	78.0	78.6	79.0	79.7	80.9	73.2	81.1	81.8	81.8	81.8	81.5	
Ghent 3	71.7	71.1	63.0	49.2	52.4	53.0	61.6	62.6	63.8	61.9	61.7	59.2	66.5	65.1	65.7	67.2	66.4	66.3	
Ghent 4	70.9	80.3	71.9	72.4	71.5	70.9	77.2	71.1	79.6	79.3	77.6	80.4	79.8	81.2	72.0	82.2	81.7	81.1	
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Haefling 1-2 (2)	0.4	1.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Mill Creek 1	74.0	56.3	68.4	74.4	80.5	69.4	80.7	77.5	83.2	78.3	84.2	80.1	85.5	79.9	84.9	73.3	85.4	80.0	
Mill Creek 2	66.6	55.6	63.4	67.1	63.6	79.1	74.7	82.4	78.6	84.2	79.8	85.4	80.8	86.0	74.1	86.3	81.3	86.4	
Mill Creek 3	78.0	63.6	58.0	78.0	86.0	72.5	83.5	80.8	87.3	81.8	87.1	82.4	87.6	75.3	87.1	82.2	87.2	82.0	
Mill Creek 4	55.6	67.8	57.9	89.9	77.7	90.6	85.4	90.8	78.3	90.8	85.4	90.8	85.4	90.8	85.4	90.8	78.3	90.8	
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Paddy's Run 13	8.1	14.1	6.3	28.0	26.3	18.9	12.7	10.0	9.2	8.9	8.3	10.0	9.9	10.4	9.9	10.5	9.9	10.6	
Trimble County 1 (75%)	80.0	64.4	79.5	65.6	79.8	73.9	79.2	74.8	79.4	75.6	80.5	70.1	81.4	76.1	81.2	76.9	81.4	76.3	
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4	
Trimble County 5	9.5	14.5	13.2	23.6	21.3	15.1	10.9	11.4	10.0	10.6	9.2	10.7	10.7	11.3	10.8	11.5	10.9	11.7	
Trimble County 6	10.4	13.8	5.6	21.6	17.0	11.4	8.3	8.5	10.3	8.1	6.2	8.5	8.4	8.8	8.5	9.1	8.6	9.2	
Trimble County 7	7.7	16.4	11.5	17.6	11.3	8.6	6.0	6.4	7.9	6.1	6.1	5.8	6.5	6.9	6.7	7.1	6.8	7.3	
Trimble County 8	2.9	5.0	2.9	13.9	10.5	6.4	4.5	4.7	5.9	4.1	4.6	5.3	5.0	5.3	5.0	5.4	5.2	5.6	
Trimble County 9	9.0	17.5	11.3	10.9	8.7	4.5	3.5	3.4	4.3	3.5	3.4	3.5	3.7	3.9	3.8	4.1	3.9	4.2	
Trimble County 10	3.7	4.6	10.0	8.5	6.4	3.4	2.5	2.5	3.1	2.6	2.6	3.0	2.7	3.0	2.9	3.1	3.0	3.3	
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1	

Kentucky Utilities Company and Louisville Gas and Electric Company

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Low Load																		
E.W. Brown 1	40.0	22.3	23.4	2.7	7.8	10.9	10.0	12.1	6.0	15.7	21.3	29.0	28.5	27.3	27.5	24.2	27.3	28.1
E.W. Brown 2	51.8	42.7	27.8	10.5	14.8	17.7	12.2	14.0	13.1	19.8	26.0	27.0	31.2	30.4	30.1	31.8	29.7	29.6
E.W. Brown 3	42.1	33.5	30.4	6.1	12.7	13.4	7.4	9.4	10.5	15.1	17.2	24.2	23.3	18.4	20.8	21.6	18.5	18.6
E.W. Brown 5	3.5	10.8	3.7	0.7	0.9	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
E.W. Brown 6	13.7	16.2	1.8	2.0	1.8	1.0	0.7	0.7	0.8	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.7
E.W. Brown 7	16.3	12.5	1.8	2.6	2.3	1.1	0.8	0.8	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
E.W. Brown 8	2.2	7.3	9.5	0.6	0.6	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
E.W. Brown 9	1.6	8.4	10.4	0.4	0.4	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
E.W. Brown 10	1.8	7.8	10.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E.W. Brown 11	2.2	5.4	5.8	0.4	0.5	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	84.2	76.5	62.1	33.9	35.7	34.6	22.7	17.3	15.5	14.9	14.3	15.2	16.4	15.9	14.7
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 1	77.5	60.9	72.9	77.1	76.5	79.4	80.9	79.7	73.6	81.6	81.6	79.1	81.1	80.7	81.3	72.4	80.9	80.4
Ghent 2	77.7	58.8	68.3	74.7	77.2	69.8	77.4	77.1	77.3	77.5	78.0	79.3	71.8	79.3	80.3	80.2	80.1	79.7
Ghent 3	71.7	71.1	63.0	41.2	46.1	46.0	54.8	56.0	56.6	53.9	52.7	50.7	56.6	54.4	55.0	56.4	55.1	55.0
Ghent 4	70.9	80.3	71.9	67.1	66.5	66.1	73.0	67.3	75.9	74.3	71.8	74.9	74.5	75.3	65.6	76.4	75.6	74.6
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	73.0	78.9	68.2	79.5	76.3	81.9	76.8	82.5	78.3	83.5	77.9	82.8	71.4	83.4	77.9
Mill Creek 2	66.6	55.6	63.4	62.8	60.4	76.9	72.7	80.8	77.1	82.2	78.0	83.2	79.2	84.1	72.6	84.5	79.7	84.6
Mill Creek 3	78.0	63.6	58.0	77.1	85.1	71.7	82.5	79.9	86.3	80.7	85.8	81.1	86.2	74.1	85.5	80.7	85.5	80.3
Mill Creek 4	55.6	67.8	57.9	89.5	77.5	90.5	85.4	90.7	78.2	90.7	85.4	90.7	85.4	90.8	85.4	90.7	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Paddy's Run 13	8.1	14.1	6.3	21.0	19.5	12.9	8.5	6.7	6.2	5.5	4.8	5.6	5.3	5.5	5.1	5.4	5.0	5.4
Trimble County 1 (75%)	80.0	64.4	79.5	64.7	78.7	72.8	78.1	73.6	78.1	74.1	78.8	68.3	78.8	73.6	78.5	74.4	78.6	73.6
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	17.5	15.2	9.9	7.0	7.3	6.4	6.3	5.1	5.7	5.4	5.7	5.3	5.6	5.3	5.7
Trimble County 6	10.4	13.8	5.6	15.6	11.7	7.3	5.1	5.2	6.3	4.7	3.4	4.3	4.1	4.2	4.0	4.2	3.9	4.2
Trimble County 7	7.7	16.4	11.5	12.4	7.4	5.3	3.6	3.8	4.7	3.4	3.1	2.9	3.0	3.2	3.0	3.1	3.0	3.2
Trimble County 8	2.9	5.0	2.9	9.5	6.8	3.8	2.6	2.7	3.3	2.2	2.3	2.5	2.2	2.3	2.1	2.2	2.1	2.3
Trimble County 9	9.0	17.5	11.3	7.2	5.4	2.6	2.0	1.9	2.3	1.8	1.6	1.5	1.5	1.6	1.5	1.6	1.5	1.7
Trimble County 10	3.7	4.6	10.0	5.5	3.8	1.9	1.4	1.3	1.6	1.2	1.1	1.3	1.1	1.1	1.1	1.2	1.1	1.2
Zorn 1	0.1	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

Kentucky Utilities Company and Louisville Gas and Electric Company Sch9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Scenario: High Gas - Base Load																		
E.W. Brown 1	40.0	22.3	23.4	13.2	25.0	33.1	30.2	34.1	21.5	29.2	30.2	36.4	34.7	34.6	34.3	30.5	35.0	36.5
E.W. Brown 2	51.8	42.7	27.8	21.0	32.8	41.3	33.9	37.0	36.3	34.6	34.0	33.0	38.1	37.7	37.4	39.8	37.9	38.3
E.W. Brown 3	42.1	33.5	30.4	19.2	33.9	36.4	23.4	29.9	31.9	29.7	26.9	32.3	30.3	24.8	28.7	31.1	28.5	29.0
E.W. Brown 5	3.5	10.8	3.7	0.8	1.0	0.6	0.4	0.4	0.5	0.5	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5
E.W. Brown 6	13.7	16.2	1.8	1.6	1.8	1.3	0.9	0.9	1.1	0.9	0.9	1.1	1.0	1.0	1.0	1.1	1.0	1.1
E.W. Brown 7	16.3	12.5	1.8	2.0	2.3	1.4	1.0	1.0	1.1	1.1	1.0	1.2	1.1	1.1	1.1	1.2	1.2	1.2
E.W. Brown 8	2.2	7.3	9.5	0.6	0.7	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
E.W. Brown 9	1.6	8.4	10.4	0.5	0.5	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
E.W. Brown 10	1.8	7.8	10.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
E.W. Brown 11	2.2	5.4	5.8	0.5	0.6	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	45.7	33.5	19.4	16.5	16.0	17.7	13.8	15.6	17.3	17.8	17.0	17.8	18.2	16.7	14.8
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ghent 1	77.5	60.9	72.9	83.2	82.5	83.8	81.6	80.6	74.5	82.7	82.9	80.4	82.5	82.2	82.7	74.1	82.6	82.0
Ghent 2	77.7	58.8	68.3	78.8	81.8	72.8	79.5	79.1	78.8	78.7	79.1	80.2	72.5	80.2	81.1	81.2	81.1	80.7
Ghent 3	71.7	71.1	63.0	67.8	62.5	63.0	60.4	62.1	62.5	58.9	57.5	55.3	61.9	60.2	60.7	62.3	61.7	61.5
Ghent 4	70.9	80.3	71.9	82.1	80.0	78.3	75.2	69.4	77.9	77.0	75.0	78.0	77.5	78.6	69.2	79.6	79.1	78.3
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	77.4	84.5	71.8	82.1	78.3	83.6	78.1	83.5	79.2	84.6	79.1	84.1	72.4	84.8	79.3
Mill Creek 2	66.6	55.6	63.4	76.5	70.1	82.5	75.3	83.3	79.1	83.8	79.1	84.4	80.3	85.3	73.5	85.6	80.6	85.6
Mill Creek 3	78.0	63.6	58.0	79.4	87.7	74.5	84.7	81.2	86.9	81.4	86.5	81.8	86.7	74.5	86.2	80.9	85.7	80.5
Mill Creek 4	55.6	67.8	57.9	90.7	78.2	90.6	85.4	90.7	78.3	90.8	85.4	90.7	85.4	90.8	85.4	90.8	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Paddy's Run 13	8.1	14.1	6.3	14.3	12.4	9.1	6.9	5.5	4.7	7.0	6.4	7.5	7.3	7.5	7.1	7.5	7.0	7.4
Trimble County 1 (75%)	80.0	64.4	79.5	67.6	83.1	76.5	80.9	76.1	80.6	75.3	79.8	69.2	80.2	74.9	79.9	75.7	80.1	75.3
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	10.8	12.6	9.3	7.1	7.1	6.1	7.1	6.6	7.5	7.4	7.7	7.1	7.5	7.0	7.3
Trimble County 6	10.4	13.8	5.6	9.5	9.8	7.3	5.4	5.4	6.3	5.5	4.4	5.8	5.7	5.9	5.5	5.8	5.4	5.6
Trimble County 7	7.7	16.4	11.5	7.4	6.9	5.4	4.0	4.1	5.0	4.1	4.2	4.0	4.3	4.4	4.1	4.4	4.1	4.3
Trimble County 8	2.9	5.0	2.9	5.5	5.9	4.2	3.0	3.1	3.8	2.8	3.1	3.5	3.2	3.4	3.1	3.3	3.2	3.3
Trimble County 9	9.0	17.5	11.3	4.1	4.6	2.9	2.2	2.2	2.9	2.4	2.3	2.3	2.4	2.5	2.4	2.5	2.4	2.5
Trimble County 10	3.7	4.6	10.0	2.9	3.4	2.3	1.6	1.6	2.1	1.7	1.7	1.9	1.7	1.8	1.8	1.9	1.8	1.9
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

Kentucky Utilities Company and Louisville Gas and Electric Company Sch9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Scenario: High Gas - High Load																		
E.W. Brown 1	40.0	22.3	23.4	15.6	28.3	36.9	33.8	38.1	24.9	33.5	35.0	42.1	40.5	41.0	40.4	36.1	41.5	43.5
E.W. Brown 2	51.8	42.7	27.8	23.7	35.6	45.0	37.6	40.8	40.2	39.0	38.7	37.6	43.6	43.7	43.3	46.1	44.2	44.8
E.W. Brown 3	42.1	33.5	30.4	22.1	37.4	40.1	26.5	33.8	35.9	34.3	31.6	37.9	35.9	30.0	34.5	37.5	34.7	35.5
E.W. Brown 5	3.5	10.8	3.7	1.1	1.4	0.9	0.6	0.6	0.7	0.7	0.7	0.8	0.7	0.8	0.8	0.9	0.9	1.0
E.W. Brown 6	13.7	16.2	1.8	2.2	2.4	1.8	1.3	1.3	1.6	1.4	1.4	1.8	1.6	1.7	1.7	1.8	1.8	1.9
E.W. Brown 7	16.3	12.5	1.8	2.6	3.1	1.9	1.3	1.4	1.6	1.5	1.5	1.8	1.7	1.8	1.8	1.9	1.9	2.0
E.W. Brown 8	2.2	7.3	9.5	0.9	1.0	0.6	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
E.W. Brown 9	1.6	8.4	10.4	0.7	0.8	0.4	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
E.W. Brown 10	1.8	7.8	10.4	0.6	0.6	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5
E.W. Brown 11	2.2	5.4	5.8	0.7	0.8	0.5	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	49.5	37.2	22.4	19.3	18.9	20.9	16.8	19.3	21.6	22.4	21.5	22.6	23.1	21.6	19.2
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ghent 1	77.5	60.9	72.9	83.6	82.9	84.3	82.2	81.4	75.2	83.5	83.8	81.4	83.5	83.3	83.8	75.0	83.7	83.3
Ghent 2	77.7	58.8	68.3	79.3	82.2	73.2	79.9	79.6	79.4	79.4	79.9	80.9	73.2	81.1	81.8	81.9	81.9	81.6
Ghent 3	71.7	71.1	63.0	70.3	64.6	65.8	63.6	65.3	65.8	62.7	61.8	59.2	66.5	65.1	65.7	67.2	66.9	66.7
Ghent 4	70.9	80.3	71.9	83.1	81.2	79.7	77.2	71.1	79.6	79.3	77.6	80.4	79.8	81.2	72.0	82.2	81.7	81.1
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Mill Creek 1	74.0	56.3	68.4	78.1	85.1	72.4	82.8	79.0	84.3	78.8	84.4	80.1	85.5	80.0	85.1	73.3	85.7	80.3
Mill Creek 2	66.6	55.6	63.4	77.7	71.1	83.4	76.4	84.2	79.8	84.7	80.0	85.4	81.0	86.1	74.2	86.4	81.4	86.4
Mill Creek 3	78.0	63.6	58.0	79.7	88.0	74.9	85.3	81.6	87.4	82.0	87.1	82.4	87.4	75.1	87.0	81.7	86.5	81.4
Mill Creek 4	55.6	67.8	57.9	90.7	78.2	90.6	85.4	90.8	78.3	90.8	85.4	90.8	85.4	90.8	85.4	90.8	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Paddy's Run 13	8.1	14.1	6.3	17.0	14.6	11.0	8.4	6.7	5.8	8.8	8.3	9.8	9.7	10.1	9.6	10.2	9.6	10.2
Trimble County 1 (75%)	80.0	64.4	79.5	68.1	83.7	77.2	81.6	76.7	81.3	76.0	80.6	70.1	81.4	76.1	81.2	76.9	81.4	76.5
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	13.0	15.1	11.5	8.8	8.9	7.7	9.1	8.8	10.2	10.2	10.7	10.0	10.6	9.9	10.3
Trimble County 6	10.4	13.8	5.6	11.7	12.0	9.1	6.8	6.9	8.1	7.2	5.9	8.0	8.0	8.4	7.8	8.3	7.8	8.2
Trimble County 7	7.7	16.4	11.5	9.2	8.5	6.9	5.1	5.3	6.5	5.4	5.8	5.7	6.3	6.5	6.1	6.5	6.2	6.4
Trimble County 8	2.9	5.0	2.9	7.0	7.4	5.4	3.9	4.1	5.0	3.8	4.4	5.0	4.8	5.0	4.7	5.0	4.8	5.0
Trimble County 9	9.0	17.5	11.3	5.3	6.0	3.9	3.0	3.0	4.0	3.3	3.3	3.4	3.7	3.8	3.6	3.9	3.7	3.9
Trimble County 10	3.7	4.6	10.0	3.9	4.4	3.1	2.2	2.2	2.9	2.5	2.5	3.0	2.6	2.9	2.8	3.0	2.9	3.0
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - Low Load																		
E.W. Brown 1	40.0	22.3	23.4	11.0	21.8	29.2	26.5	30.2	18.3	24.9	25.5	30.8	28.9	28.3	28.3	24.9	28.5	29.6
E.W. Brown 2	51.8	42.7	27.8	18.3	30.1	37.5	30.2	33.2	32.4	30.3	29.3	28.4	32.4	31.6	31.4	33.4	31.5	31.7
E.W. Brown 3	42.1	33.5	30.4	16.4	30.4	32.6	20.3	26.1	27.8	25.3	22.4	26.7	24.7	19.9	23.1	25.0	22.5	22.8
E.W. Brown 5	3.5	10.8	3.7	0.6	0.7	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3
E.W. Brown 6	13.7	16.2	1.8	1.1	1.3	0.9	0.6	0.6	0.7	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6
E.W. Brown 7	16.3	12.5	1.8	1.5	1.7	1.0	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
E.W. Brown 8	2.2	7.3	9.5	0.4	0.5	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
E.W. Brown 9	1.6	8.4	10.4	0.3	0.4	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
E.W. Brown 10	1.8	7.8	10.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
E.W. Brown 11	2.2	5.4	5.8	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	41.7	29.8	16.5	13.9	13.4	14.7	11.2	12.4	13.4	13.7	13.0	13.5	13.8	12.4	11.0
Cane Run 11	-0.1	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 1	77.5	60.9	72.9	82.6	82.1	83.2	80.9	79.8	73.7	81.6	81.6	79.1	81.1	80.7	81.3	72.8	81.2	80.4
Ghent 2	77.7	58.8	68.3	78.4	81.4	72.4	79.0	78.6	78.1	77.9	78.2	79.3	71.8	79.3	80.3	80.3	80.2	79.8
Ghent 3	71.7	71.1	63.0	64.9	60.1	59.8	56.7	58.6	58.7	54.7	52.7	50.7	56.6	54.4	55.0	56.5	55.6	55.4
Ghent 4	70.9	80.3	71.9	80.8	78.5	76.6	73.0	67.3	75.9	74.3	71.8	74.9	74.5	75.3	65.6	76.3	75.6	74.7
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	76.6	83.8	71.2	81.4	77.7	82.9	77.3	82.7	78.3	83.5	78.1	83.0	71.4	83.7	78.2
Mill Creek 2	66.6	55.6	63.4	75.2	69.0	81.5	74.2	82.4	78.2	82.8	78.1	83.2	79.5	84.3	72.7	84.6	79.7	84.6
Mill Creek 3	78.0	63.6	58.0	79.0	87.3	74.0	84.1	80.7	86.4	80.9	85.8	81.1	85.9	73.8	85.3	80.0	84.7	79.6
Mill Creek 4	55.6	67.8	57.9	90.7	78.1	90.5	85.4	90.7	78.2	90.7	85.4	90.7	85.4	90.8	85.4	90.7	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Paddy's Run 13	8.1	14.1	6.3	11.8	10.4	7.5	5.6	4.4	3.8	5.4	4.8	5.5	5.3	5.4	5.0	5.3	4.9	5.2
Trimble County 1 (75%)	80.0	64.4	79.5	67.0	82.5	75.9	80.3	75.4	79.8	74.5	78.9	68.3	78.8	73.6	78.6	74.4	78.6	73.8
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	8.8	10.3	7.5	5.6	5.6	4.8	5.4	4.9	5.4	5.2	5.4	4.9	5.1	4.7	4.9
Trimble County 6	10.4	13.8	5.6	7.7	7.9	5.7	4.2	4.2	4.9	4.1	3.2	4.1	3.9	4.0	3.6	3.8	3.5	3.7
Trimble County 7	7.7	16.4	11.5	5.8	5.5	4.2	3.0	3.1	3.8	3.0	2.9	2.8	2.9	2.9	2.7	2.8	2.6	2.8
Trimble County 8	2.9	5.0	2.9	4.3	4.6	3.2	2.3	2.3	2.8	2.0	2.2	2.3	2.1	2.2	2.0	2.1	2.0	2.1
Trimble County 9	9.0	17.5	11.3	3.1	3.5	2.2	1.7	1.7	2.1	1.7	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Trimble County 10	3.7	4.6	10.0	2.2	2.5	1.7	1.2	1.2	1.5	1.2	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Zorn 1	0.1	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

Part 4

Kentucky Utilities Company and Louisville Gas and Electric Company

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Scenario: Low Gas - Base Load																		
E.W. Brown 1	40.0	22.3	23.4	0.5	3.4	12.8	11.7	12.6	3.0	10.3	11.3	15.3	14.5	14.5	14.9	13.9	15.4	17.8
E.W. Brown 2	51.8	42.7	27.8	2.1	13.1	20.2	14.2	15.9	11.8	16.1	14.7	15.7	17.1	17.1	16.9	18.2	17.0	19.3
E.W. Brown 3	42.1	33.5	30.4	1.4	7.1	15.6	8.6	9.8	6.0	10.2	9.1	11.8	11.1	9.9	9.8	10.7	9.9	11.2
E.W. Brown 5	3.5	10.8	3.7	2.4	1.3	0.7	0.6	0.6	0.8	0.7	0.6	0.7	0.6	0.7	0.7	0.7	0.7	0.8
E.W. Brown 6	13.7	16.2	1.8	5.7	3.4	1.4	1.0	1.1	2.1	1.2	1.1	1.3	1.1	1.2	1.2	1.3	1.3	1.4
E.W. Brown 7	16.3	12.5	1.8	6.9	4.6	1.5	1.1	1.2	2.0	1.2	1.2	1.3	1.2	1.3	1.4	1.4	1.4	1.5
E.W. Brown 8	2.2	7.3	9.5	0.8	1.0	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
E.W. Brown 9	1.6	8.4	10.4	0.5	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
E.W. Brown 10	1.8	7.8	10.4	0.4	0.5	0.3	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
E.W. Brown 11	2.2	5.4	5.8	0.6	0.7	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	87.8	87.5	68.3	66.7	77.4	86.8	73.6	80.2	70.5	71.3	63.5	61.0	56.8	56.6	56.7
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ghent 1	77.5	60.9	72.9	76.5	77.3	78.0	74.3	73.0	65.9	75.0	72.7	72.7	74.5	74.7	80.5	73.3	81.6	78.2
Ghent 2	77.7	58.8	68.3	73.5	77.6	69.6	77.2	74.6	72.8	73.5	73.6	76.2	69.8	77.7	78.6	79.1	78.9	78.6
Ghent 3	71.7	71.1	63.0	44.1	42.8	49.7	44.8	40.6	36.1	35.8	32.7	39.0	44.6	44.0	45.2	47.8	46.4	47.0
Ghent 4	70.9	80.3	71.9	67.5	63.4	67.5	62.3	55.9	57.9	61.8	60.1	66.3	65.5	68.6	61.5	76.2	74.5	69.9
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	70.3	78.8	68.8	78.2	74.3	78.8	74.7	79.1	75.7	80.4	76.1	80.8	69.7	81.6	76.8
Mill Creek 2	66.6	55.6	63.4	62.2	60.6	77.0	69.5	75.2	71.8	77.1	72.7	79.7	77.4	83.2	71.8	83.5	78.9	84.0
Mill Creek 3	78.0	63.6	58.0	75.5	84.8	71.8	81.2	77.7	83.3	78.3	83.2	79.5	84.6	72.0	83.1	77.9	82.9	78.1
Mill Creek 4	55.6	67.8	57.9	90.0	77.6	90.4	85.4	90.3	78.0	90.4	85.1	90.5	85.4	90.8	85.4	90.8	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Paddy's Run 13	8.1	14.1	6.3	40.0	32.4	15.8	11.1	11.1	16.9	19.5	12.1	13.1	12.5	12.6	12.2	13.4	12.2	13.4
Trimble County 1 (75%)	80.0	64.4	79.5	63.0	78.7	73.3	78.0	72.6	75.6	71.8	76.4	65.7	75.8	72.1	76.6	72.4	76.8	72.3
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	29.8	23.5	12.3	8.7	10.7	12.8	10.8	9.4	9.7	9.8	10.1	9.8	10.4	9.6	10.5
Trimble County 6	10.4	13.8	5.6	27.0	18.8	9.2	6.4	7.9	12.9	8.1	6.0	7.2	7.3	7.6	7.3	7.8	7.3	7.9
Trimble County 7	7.7	16.4	11.5	21.4	13.1	6.8	5.1	5.6	11.4	5.9	5.7	4.9	5.4	5.6	5.5	5.8	5.5	5.9
Trimble County 8	2.9	5.0	2.9	16.8	11.9	4.9	3.7	4.0	8.5	3.9	4.1	4.6	3.9	4.1	4.0	4.2	4.1	4.4
Trimble County 9	9.0	17.5	11.3	12.8	9.8	3.4	2.7	2.9	6.3	3.2	2.9	3.1	2.8	2.9	2.9	3.1	3.0	3.2
Trimble County 10	3.7	4.6	10.0	9.8	7.4	2.5	1.9	2.0	4.5	2.3	2.1	2.2	1.9	2.1	2.1	2.2	2.2	2.4
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - High Load																		
E.W. Brown 1	40.0	22.3	23.4	0.8	4.2	14.8	13.7	14.7	3.8	12.3	13.9	18.7	18.2	18.4	19.0	17.8	19.7	22.8
E.W. Brown 2	51.8	42.7	27.8	2.7	14.8	22.8	16.4	18.3	13.8	18.8	17.6	18.9	20.9	21.1	21.0	22.7	21.4	24.0
E.W. Brown 3	42.1	33.5	30.4	1.9	8.5	17.9	10.2	11.5	7.4	12.3	11.3	14.8	14.1	12.6	12.7	13.8	12.9	14.5
E.W. Brown 5	3.5	10.8	3.7	3.1	1.7	1.1	0.9	0.9	1.1	1.0	0.9	1.1	1.0	1.1	1.1	1.2	1.2	1.3
E.W. Brown 6	13.7	16.2	1.8	7.3	4.4	2.0	1.4	1.6	2.9	1.7	1.7	2.0	1.8	2.0	2.0	2.2	2.1	2.3
E.W. Brown 7	16.3	12.5	1.8	8.6	5.9	2.1	1.4	1.7	2.8	1.8	1.8	2.1	1.9	2.1	2.2	2.3	2.3	2.4
E.W. Brown 8	2.2	7.3	9.5	1.1	1.4	0.9	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.9	0.9	0.9	0.9	1.0
E.W. Brown 9	1.6	8.4	10.4	0.7	0.9	0.5	0.5	0.4	0.5	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.7
E.W. Brown 10	1.8	7.8	10.4	0.5	0.7	0.4	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6
E.W. Brown 11	2.2	5.4	5.8	0.8	1.0	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.8	0.7	0.8	0.8	0.8
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	87.8	88.0	70.1	69.2	78.8	87.4	74.6	81.9	73.2	74.4	67.2	66.0	62.3	62.7	60.8
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ghent 1	77.5	60.9	72.9	77.4	78.2	79.2	75.7	74.7	67.8	76.9	75.3	74.9	76.9	77.0	81.9	74.2	82.7	80.1
Ghent 2	77.7	58.8	68.3	74.0	78.2	70.2	77.6	75.4	73.6	74.5	74.7	77.2	70.5	78.6	79.4	80.0	79.8	79.6
Ghent 3	71.7	71.1	63.0	47.8	46.1	53.1	48.5	44.4	40.3	40.4	37.6	43.8	49.9	49.6	50.9	53.5	52.1	53.0
Ghent 4	70.9	80.3	71.9	70.4	66.5	70.1	65.1	58.8	61.8	65.7	64.3	70.3	69.5	72.6	65.2	79.2	77.6	73.8
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Mill Creek 1	74.0	56.3	68.4	70.7	79.6	69.4	78.8	74.8	79.3	75.4	79.9	76.5	81.4	77.0	81.8	70.5	82.5	77.7
Mill Creek 2	66.6	55.6	63.4	64.1	62.2	78.2	70.8	76.5	72.9	78.6	74.1	81.1	78.2	84.1	72.5	84.5	79.7	84.9
Mill Creek 3	78.0	63.6	58.0	75.8	85.2	72.3	81.7	78.2	83.8	78.9	83.9	80.2	85.3	72.7	84.0	78.8	83.7	78.8
Mill Creek 4	55.6	67.8	57.9	90.2	77.7	90.5	85.4	90.4	78.1	90.5	85.2	90.6	85.4	90.8	85.4	90.8	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Paddy's Run 13	8.1	14.1	6.3	44.7	36.4	18.9	13.5	13.4	19.4	23.6	15.6	17.2	16.7	16.9	16.5	18.2	16.7	18.3
Trimble County 1 (75%)	80.0	64.4	79.5	63.2	79.2	73.8	78.5	73.1	76.0	72.4	77.0	66.5	76.9	73.0	77.6	73.4	77.8	73.3
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	33.7	27.0	15.0	10.8	13.3	15.5	13.8	12.3	13.1	13.4	13.9	13.5	14.5	13.5	14.7
Trimble County 6	10.4	13.8	5.6	31.1	22.0	11.5	8.0	10.0	15.8	10.5	8.0	9.9	10.3	10.7	10.4	11.2	10.5	11.3
Trimble County 7	7.7	16.4	11.5	25.0	15.5	8.6	6.6	7.2	14.1	7.8	7.9	6.9	7.8	8.1	8.0	8.6	8.0	8.7
Trimble County 8	2.9	5.0	2.9	20.0	14.3	6.4	4.9	5.3	10.7	5.3	5.8	6.6	5.8	6.1	6.0	6.4	6.1	6.6
Trimble County 9	9.0	17.5	11.3	15.5	11.9	4.5	3.6	3.9	8.1	4.4	4.2	4.5	4.3	4.5	4.5	4.8	4.6	5.0
Trimble County 10	3.7	4.6	10.0	12.1	9.1	3.4	2.6	2.8	6.0	3.2	3.0	3.4	3.0	3.3	3.3	3.5	3.5	3.7
Zorn 1	0.1	0.9	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch9

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - Low Load																		
E.W. Brown 1	40.0	22.3	23.4	0.4	2.6	10.8	9.8	10.7	2.3	8.4	9.0	12.1	11.2	11.1	11.3	10.5	11.5	13.4
E.W. Brown 2	51.8	42.7	27.8	1.6	11.4	17.7	12.1	13.6	10.0	13.5	11.9	12.7	13.5	13.4	13.1	14.1	13.1	14.9
E.W. Brown 3	42.1	33.5	30.4	1.0	5.8	13.4	7.2	8.2	4.8	8.2	7.2	9.2	8.5	7.5	7.3	8.0	7.3	8.3
E.W. Brown 5	3.5	10.8	3.7	1.8	0.9	0.5	0.4	0.4	0.5	0.4	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.4
E.W. Brown 6	13.7	16.2	1.8	4.4	2.6	1.0	0.7	0.8	1.5	0.8	0.7	0.8	0.6	0.7	0.7	0.7	0.7	0.8
E.W. Brown 7	16.3	12.5	1.8	5.4	3.5	1.1	0.8	0.9	1.4	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.9
E.W. Brown 8	2.2	7.3	9.5	0.5	0.7	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
E.W. Brown 9	1.6	8.4	10.4	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
E.W. Brown 10	1.8	7.8	10.4	0.2	0.3	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
E.W. Brown 11	2.2	5.4	5.8	0.4	0.5	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Cane Run 4	56.7	40.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	66.1	45.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	36.2	25.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	19.7	76.8	87.8	87.0	66.3	64.1	75.9	86.1	72.5	78.2	67.6	67.8	59.3	55.5	50.7	49.9	52.0
Cane Run 11	-0.1	0.2	-0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 1	77.5	60.9	72.9	75.4	76.3	76.6	72.7	71.1	63.7	72.7	69.5	70.0	71.7	71.9	78.6	72.0	80.1	75.7
Ghent 2	77.7	58.8	68.3	72.8	76.8	69.1	76.7	73.7	72.0	72.4	72.5	75.3	69.1	76.8	77.8	78.2	78.0	77.6
Ghent 3	71.7	71.1	63.0	40.2	39.2	46.2	40.9	36.6	31.8	31.2	27.7	33.8	38.9	38.1	39.1	41.6	40.1	40.5
Ghent 4	70.9	80.3	71.9	64.3	59.9	64.7	59.3	52.6	53.5	57.4	55.4	61.8	60.8	64.0	57.0	72.3	70.5	65.1
Green River 3	59.3	49.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	82.8	71.3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	0.4	1.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Mill Creek 1	74.0	56.3	68.4	69.7	78.0	68.2	77.6	73.7	78.2	74.0	78.3	74.8	79.4	75.3	80.0	68.9	80.8	75.8
Mill Creek 2	66.6	55.6	63.4	60.1	58.9	75.7	68.2	73.7	70.5	75.5	71.0	78.2	76.5	82.3	71.1	82.5	78.0	83.0
Mill Creek 3	78.0	63.6	58.0	75.1	84.4	71.4	80.7	77.1	82.7	77.7	82.6	78.8	83.7	71.3	82.2	77.0	82.2	77.3
Mill Creek 4	55.6	67.8	57.9	89.9	77.5	90.3	85.4	90.2	78.0	90.3	85.0	90.4	85.4	90.8	85.4	90.7	78.3	90.8
Paddy's Run 11&12	0.2	-0.1	-0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Paddy's Run 13	8.1	14.1	6.3	35.3	28.3	12.9	9.0	9.1	14.4	15.8	9.1	9.7	9.0	9.0	8.7	9.5	8.6	9.5
Trimble County 1 (75%)	80.0	64.4	79.5	62.9	78.2	72.8	77.5	72.1	75.2	71.3	75.8	64.8	74.6	71.1	75.6	71.4	75.8	71.2
Trimble County 2 (75%)	58.8	84.2	61.9	79.6	74.4	81.4	81.4	81.4	81.4	81.4	81.4	81.4	74.4	81.4	81.4	81.4	81.4	81.4
Trimble County 5	9.5	14.5	13.2	25.9	20.2	9.9	6.9	8.5	10.5	8.3	6.9	7.0	6.9	7.1	6.8	7.2	6.6	7.2
Trimble County 6	10.4	13.8	5.6	23.0	15.9	7.3	5.0	6.1	10.4	6.1	4.4	5.1	5.0	5.2	5.0	5.3	4.9	5.3
Trimble County 7	7.7	16.4	11.5	17.9	10.9	5.3	4.0	4.3	9.0	4.3	4.1	3.4	3.6	3.7	3.6	3.8	3.6	3.9
Trimble County 8	2.9	5.0	2.9	13.9	9.7	3.8	2.8	3.0	6.6	2.8	2.9	3.1	2.5	2.6	2.6	2.7	2.6	2.8
Trimble County 9	9.0	17.5	11.3	10.4	7.9	2.6	2.0	2.1	4.8	2.3	2.0	2.0	1.8	1.8	1.8	1.9	1.8	2.0
Trimble County 10	3.7	4.6	10.0	7.8	5.8	1.9	1.4	1.5	3.4	1.6	1.3	1.4	1.2	1.3	1.3	1.3	1.3	1.4
Zorn 1	0.1	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dix Dam 1-3	27.5	35.5	28.2	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1	27.0	27.1	27.1	27.1
Ohio Falls 1-8	57.5	52.1	60.0	47.0	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3	51.2	51.3	51.3	51.3
Brown Solar	NA	NA	22.4	22.4	22.3	22.1	22.0	21.9	21.9	21.9	21.7	21.6	21.5	21.4	21.4	21.3	21.1	21.1

(1) Combustion turbines to be reported as a composite facilty.

(2) Haefling 1-2 actuals include Haefling 3

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company

Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Base Load																		
E.W. Brown 1	12,407	12,983	12,628	10,917	11,041	10,937	11,002	10,962	10,793	10,903	10,885	10,828	10,739	10,771	10,712	10,712	10,748	10,752
E.W. Brown 2	10,675	11,142	11,294	10,679	10,569	10,573	10,572	10,550	10,583	10,572	10,547	10,487	10,489	10,496	10,481	10,475	10,495	10,505
E.W. Brown 3	11,397	11,646	11,606	11,415	11,473	11,462	11,413	11,419	11,409	11,253	11,264	11,292	11,220	11,239	11,308	11,376	11,331	11,319
E.W. Brown 5	16,513	13,490	13,316	12,556	12,656	12,942	13,271	13,401	13,765	13,856	13,803	13,847	13,815	13,767	13,740	13,729	13,710	13,718
E.W. Brown 6	12,092	10,609	11,694	11,019	11,070	11,185	11,284	11,355	11,442	11,569	11,584	11,579	11,582	11,560	11,562	11,558	11,551	11,544
E.W. Brown 7	11,182	10,605	11,599	11,017	11,003	11,135	11,195	11,209	11,366	11,519	11,543	11,505	11,527	11,553	11,564	11,556	11,560	11,546
E.W. Brown 8	15,416	12,874	12,753	12,852	13,152	13,276	14,329	14,691	14,805	14,638	14,592	14,686	14,631	14,582	14,530	14,517	14,486	14,505
E.W. Brown 9	16,309	13,215	12,764	12,807	12,968	13,317	13,998	13,989	14,033	13,999	13,899	13,990	13,960	13,940	13,898	13,900	13,882	13,889
E.W. Brown 10	15,629	13,004	12,590	12,766	12,884	13,167	13,468	13,487	13,537	13,489	13,476	13,490	13,461	13,462	13,431	13,435	13,421	13,427
E.W. Brown 11	15,911	13,569	13,521	12,836	13,072	13,154	14,122	14,269	14,322	14,234	14,152	14,241	14,178	14,140	14,093	14,084	14,057	14,072
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,840	6,856	6,902	7,081	7,102	7,153	7,155	7,141	7,150	7,221	7,194	7,178	7,122	7,151	7,139
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,472	10,470	10,489	10,486	10,490	10,488	10,490	10,490	10,491	10,490	10,491	10,489	10,491	10,491	10,492
Ghent 2	10,688	10,629	10,335	10,334	10,335	10,331	10,331	10,334	10,330	10,336	10,340	10,343	10,345	10,340	10,343	10,347	10,346	10,346
Ghent 3	10,912	11,003	11,057	11,131	11,111	11,119	11,113	11,119	11,112	11,110	11,109	11,100	11,104	11,113	11,107	11,107	11,112	11,110
Ghent 4	10,912	10,930	10,835	10,818	10,815	10,819	10,813	10,810	10,802	10,812	10,816	10,807	10,804	10,806	10,814	10,802	10,804	10,806
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	.NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,417	10,426	10,421	10,418	10,431	10,438	10,441	10,448	10,455	10,459	10,454	10,454	10,454	10,456	10,454
Mill Creek 2	10,693	10,629	10,773	10,647	10,646	10,646	10,643	10,648	10,650	10,655	10,656	10,661	10,659	10,659	10,658	10,661	10,660	10,661
Mill Creek 3	10,674	10,858	10,745	10,500	10,505	10,484	10,479	10,496	10,507	10,504	10,504	10,508	10,507	10,505	10,505	10,506	10,504	10,503
Mill Creek 4	10,836	10,388	10,497	10,411	10,417	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,262	10,915	10,742	11,190	11,214	11,033	13,078	13,149	13,150	13,163	13,138	13,138	13,135	13,118	13,115
Trimble County 1 (75%)	10,746	8,085	10,861	10,615	10,629	10,618	10,621	10,627	10,625	10,638	10,636	10,648	10,646	10,642	10,644	10,650	10,644	10,644
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,091	10,981	11,046	11,233	11,211	11,227	11,624	11,952	12,040	12,229	12,127	12,086	12,022	11,989	11,952
Trimble County 6	11,958	10,791	11,094	11,108	11,006	11,077	11,250	11,227	11,388	11,618	11,872	11,971	12,090	12,028	11,973	11,969	11,924	11,892
Trimble County 7	12,342	11,043	11,163	11,121	10,932	11,109	11,246	11,229	11,430	11,611	11,891	11,873	11,980	11,946	11,949	11,940	11,881	11,854
Trimble County 8	12,854	11,149	11,658	11,106	11,006	11,141	11,266	11,249	11,429	11,604	11,841	11,883	11,883	11,819	11,829	11,825	11,799	11,780
Trimble County 9	12,491	10,664	11,024	11,111	11,063	11,167	11,281	11,267	11,409	11,602	11,780	11,814	11,825	11,772	11,784	11,780	11,764	11,736
Trimble County 10	12,634	11,331	11,288	11,104	11,072	11,213	11,284	11,286	11,407	11,595	11,695	11,730	11,715	11,674	11,685	11,680	11,665	11,651
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	2014 (ACTUAL)	2015	2016	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - High Load																		
E.W. Brown 1	12,407	12,983	12,628	10,902	11,025	10,927	10,984	10,936	10,781	10,863	10,847	10,779	10,699	10,730	10,678	10,678	10,709	10,710
E.W. Brown 2	10,675	11,142	11,294	10,662	10,558	10,561	10,563	10,538	10,570	10,551	10,528	10,467	10,467	10,473	10,461	10,454	10,472	10,480
E.W. Brown 3	11,397	11,646	11,606	11,390	11,451	11,439	11,395	11,396	11,381	11,223	11,230	11,244	11,178	11,199	11,256	11,311	11,278	11,265
E.W. Brown 5	16,513	13,490	13,316	12,535	12,630	12,906	13,226	13,348	13,686	13,762	13,700	13,733	13,699	13,647	13,618	13,605	13,581	13,585
E.W. Brown 6	12,092	10,609	11,694	11,000	11,048	11,158	11,264	11,333	11,415	11,533	11,546	11,534	11,538	11,512	11,515	11,511	11,502	11,491
E.W. Brown 7	11,182	10,605	11,599	11,002	10,987	11,113	11,180	11,195	11,340	11,481	11,500	11,455	11,477	11,492	11,504	11,494	11,498	11,480
E.W. Brown 8	15,416	12,874	12,753	12,825	13,108	13,245	14,221	14,573	14,682	14,516	14,450	14,533	14,473	14,419	14,366	14,347	14,310	14,326
E.W. Brown 9	16,309	13,215	12,764	12,784	12,936	13,290	13,934	13,923	13,970	13,924	13,813	13,898	13,864	13,846	13,807	13,804	13,782	13,786
E.W. Brown 10	15,629	13,004	12,590	12,747	12,855	13,139	13,431	13,444	13,497	13,444	13,431	13,430	13,397	13,405	13,375	13,376	13,361	13,361
E.W. Brown 11	15,911	13,569	13,521	12,813	13,035	13,124	14,043	14,170	14,225	14,133	14,040	14,120	14,051	14,012	13,964	13,949	13,918	13,931
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,838	6,854	6,895	7,042	7,078	7,122	7,126	7,113	7,122	7,184	7,159	7,143	7,090	7,117	7,106
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,471	10,470	10,487	10,485	10,488	10,486	10,487	10,486	10,488	10,487	10,488	10,486	10,487	10,487	10,488
Ghent 2	10,688	10,629	10,335	10,335	10,337	10,333	10,333	10,337	10,332	10,339	10,343	10,346	10,349	10,344	10,347	10,350	10,350	10,350
Ghent 3	10,912	11,003	11,057	11,122	11,104	11,111	11,105	11,111	11,104	11,101	11,100	11,090	11,094	11,100	11,096	11,095	11,098	11,097
Ghent 4	10,912	10,930	10,835	10,811	10,809	10,812	10,805	10,802	10,796	10,804	10,805	10,797	10,794	10,796	10,802	10,793	10,794	10,795
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,422	10,431	10,427	10,423	10,437	10,444	10,448	10,455	10,463	10,467	10,462	10,463	10,463	10,464	10,463
Mill Creek 2	10,693	10,629	10,773	10,647	10,647	10,647	10,643	10,650	10,653	10,657	10,659	10,663	10,663	10,663	10,662	10,665	10,665	10,665
Mill Creek 3	10,674	10,858	10,745	10,502	10,507	10,488	10,482	10,499	10,510	10,508	10,509	10,512	10,512	10,510	10,510	10,511	10,510	10,509
Mill Creek 4	10,836	10,388	10,497	10,411	10,417	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,206	10,876	10,723	11,164	11,203	11,028	13,011	13,079	13,072	13,083	13,051	13,050	13,046	13,027	13,021
Trimble County 1 (75%)	10,746	8,085	10,861	10,621	10,635	10,625	10,627	10,634	10,632	10,646	10,645	10,658	10,657	10,653	10,655	10,662	10,656	10,656
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,061	10,955	11,020	11,205	11,184	11,203	11,587	11,891	11,972	12,137	12,038	12,001	11,941	11,911	11,876
Trimble County 6	11,958	10,791	11,094	11,080	10,979	11,049	11,222	11,201	11,356	11,579	11,809	11,904	12,009	11,942	11,896	11,890	11,847	11,815
Trimble County 7	12,342	11,043	11,163	11,093	10,910	11,080	11,219	11,200	11,397	11,571	11,826	11,797	11,902	11,863	11,868	11,858	11,797	11,771
Trimble County 8	12,854	11,149	11,658	11,081	10,981	11,109	11,238	11,220	11,397	11,563	11,779	11,810	11,807	11,740	11,751	11,746	11,719	11,697
Trimble County 9	12,491	10,664	11,024	11,088	11,035	11,132	11,252	11,238	11,378	11,558	11,718	11,742	11,749	11,693	11,705	11,700	11,683	11,652
Trimble County 10	12,634	11,331	11,288	11,082	11,045	11,176	11,254	11,257	11,377	11,548	11,636	11,663	11,645	11,601	11,613	11,608	11,591	11,572
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Low Load																		
E.W. Brown 1	12,407	12,983	12,628	10,932	11,054	10,948	11,020	10,987	10,804	10,944	10,924	10,879	10,781	10,815	10,749	10,747	10,789	10,795
E.W. Brown 2	10,675	11,142	11,294	10,696	10,580	10,587	10,580	10,562	10,595	10,594	10,566	10,508	10,512	10,520	10,503	10,498	10,519	10,530
E.W. Brown 3	11,397	11,646	11,606	11,440	11,494	11,484	11,429	11,438	11,434	11,282	11,297	11,341	11,264	11,280	11,363	11,444	11,386	11,375
E.W. Brown 5	16,513	13,490	13,316	12,578	12,680	12,977	13,316	13,456	13,844	13,948	13,901	13,960	13,934	13,892	13,862	13,858	13,840	13,852
E.W. Brown 6	12,092	10,609	11,694	11,036	11,089	11,208	11,303	11,376	11,467	11,604	11,619	11,623	11,625	11,607	11,606	11,605	11,597	11,595
E.W. Brown 7	11,182	10,605	11,599	11,031	11,018	11,155	11,209	11,223	11,390	11,555	11,582	11,553	11,575	11,612	11,620	11,615	11,619	11,610
E.W. Brown 8	15,416	12,874	12,753	12,880	13,194	13,309	14,432	14,806	14,923	14,759	14,725	14,839	14,792	14,752	14,694	14,697	14,665	14,687
E.W. Brown 9	16,309	13,215	12,764	12,830	12,999	13,344	14,059	14,058	14,101	14,071	13,977	14,087	14,059	14,039	13,989	14,007	13,985	13,997
E.W. Brown 10	15,629	13,004	12,590	12,786	12,910	13,193	13,504	13,530	13,579	13,533	13,514	13,549	13,516	13,521	13,484	13,502	13,484	13,491
E.W. Brown 11	15,911	13,569	13,521	12,859	13,110	13,185	14,199	14,366	14,419	14,334	14,257	14,386	14,309	14,277	14,222	14,229	14,198	14,218
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,842	6,858	6,910	7,081	7,126	7,184	7,186	7,169	7,177	7,257	7,229	7,213	7,154	7,183	7,170
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,472	10,471	10,491	10,488	10,493	10,491	10,493	10,495	10,495	10,495	10,496	10,495	10,496	10,496	10,497
Ghent 2	10,688	10,629	10,335	10,332	10,333	10,329	10,328	10,332	10,327	10,333	10,336	10,339	10,341	10,336	10,339	10,342	10,342	10,341
Ghent 3	10,912	11,003	11,057	11,140	11,120	11,128	11,121	11,129	11,122	11,121	11,120	11,111	11,117	11,128	11,120	11,121	11,128	11,126
Ghent 4	10,912	10,930	10,835	10,827	10,823	10,827	10,822	10,820	10,810	10,823	10,829	10,820	10,816	10,819	10,830	10,816	10,819	10,821
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,412	10,421	10,416	10,413	10,426	10,432	10,434	10,440	10,447	10,450	10,444	10,445	10,444	10,446	10,444
Mill Creek 2	10,693	10,629	10,773	10,647	10,644	10,645	10,642	10,646	10,648	10,652	10,654	10,657	10,655	10,655	10,654	10,657	10,656	10,656
Mill Creek 3	10,674	10,858	10,745	10,498	10,502	10,481	10,475	10,492	10,503	10,499	10,499	10,502	10,502	10,499	10,499	10,500	10,497	10,497
Mill Creek 4	10,836	10,388	10,497	10,410	10,416	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,316	10,955	10,761	11,211	11,224	11,039	13,137	13,207	13,215	13,228	13,208	13,209	13,208	13,194	13,194
Trimble County 1 (75%)	10,746	8,085	10,861	10,610	10,623	10,612	10,616	10,621	10,618	10,629	10,627	10,637	10,635	10,631	10,632	10,638	10,631	10,631
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,122	11,008	11,071	11,259	11,236	11,251	11,658	12,011	12,102	12,315	12,210	12,163	12,096	12,064	12,025
Trimble County 6	11,958	10,791	11,094	11,135	11,033	11,102	11,276	11,253	11,418	11,654	11,934	12,034	12,166	12,108	12,046	12,043	11,998	11,968
Trimble County 7	12,342	11,043	11,163	11,147	10,952	11,137	11,272	11,256	11,460	11,649	11,952	11,947	12,053	12,026	12,026	12,018	11,962	11,938
Trimble County 8	12,854	11,149	11,658	11,129	11,029	11,170	11,292	11,278	11,459	11,644	11,901	11,955	11,957	11,895	11,904	11,902	11,879	11,864
Trimble County 9	12,491	10,664	11,024	11,133	11,090	11,199	11,308	11,295	11,439	11,646	11,841	11,884	11,900	11,850	11,861	11,858	11,844	11,822
Trimble County 10	12,634	11,331	11,288	11,125	11,097	11,247	11,312	11,315	11,438	11,641	11,751	11,796	11,784	11,746	11,755	11,752	11,739	11,731
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - Base Load																		
E.W. Brown 1	12,407	12,983	12,628	10,785	10,700	10,640	10,771	10,766	10,600	10,754	10,774	10,768	10,724	10,740	10,691	10,689	10,703	10,697
E.W. Brown 2	10,675	11,142	11,294	10,552	10,489	10,480	10,497	10,489	10,495	10,502	10,493	10,480	10,484	10,490	10,476	10,468	10,480	10,477
E.W. Brown 3	11,397	11,646	11,606	11,276	11,208	11,128	11,153	11,178	11,177	11,158	11,165	11,182	11,162	11,162	11,193	11,205	11,209	11,213
E.W. Brown 5	16,513	13,490	13,316	13,197	13,237	13,924	14,112	14,157	14,284	14,176	14,370	14,471	14,485	14,448	14,414	14,400	14,387	14,388
E.W. Brown 6	12,092	10,609	11,694	11,166	11,190	11,592	11,607	11,650	11,756	11,692	11,695	11,683	11,797	11,820	11,825	11,819	11,810	11,805
E.W. Brown 7	11,182	10,605	11,599	11,169	11,210	11,492	11,573	11,579	11,588	11,606	11,651	11,630	11,647	11,777	11,791	11,782	11,787	11,772
E.W. Brown 8	15,416	12,874	12,753	13,951	14,087	14,741	15,088	15,160	15,247	15,206	15,118	15,209	15,155	15,131	15,080	15,074	15,042	15,064
E.W. Brown 9	16,309	13,215	12,764	13,467	13,541	14,061	14,578	14,562	14,652	14,546	14,424	14,542	14,504	14,551	14,511	14,511	14,489	14,503
E.W. Brown 10	15,629	13,004	12,590	13,105	13,147	13,535	14,085	14,072	14,142	14,085	14,042	14,084	14,061	14,046	14,016	14,020	14,003	14,016
E.W. Brown 11	15,911	13,569	13,521	13,601	13,700	14,327	14,838	14,800	14,873	14,826	14,734	14,822	14,779	14,779	14,735	14,733	14,705	14,723
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	7,049	7,044	7,308	7,334	7,340	7,356	7,320	7,341	7,332	7,327	7,314	7,325	7,340	7,363	7,355
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,468	10,471	10,485	10,486	10,490	10,487	10,490	10,490	10,491	10,490	10,491	10,489	10,489	10,490	10,492
Ghent 2	10,688	10,629	10,335	10,342	10,349	10,346	10,342	10,345	10,335	10,339	10,341	10,343	10,345	10,340	10,343	10,347	10,347	10,347
Ghent 3	10,912	11,003	11,057	11,088	11,080	11,093	11,099	11,101	11,098	11,105	11,108	11,100	11,104	11,113	11,107	11,106	11,107	11,108
Ghent 4	10,912	10,930	10,835	10,787	10,792	10,799	10,813	10,810	10,802	10,812	10,816	10,807	10,803	10,806	10,814	10,802	10,805	10,805
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,447	10,461	10,451	10,438	10,446	10,448	10,446	10,449	10,455	10,459	10,454	10,455	10,454	10,459	10,457
Mill Creek 2	10,693	10,629	10,773	10,652	10,656	10,658	10,653	10,658	10,658	10,658	10,657	10,661	10,659	10,660	10,658	10,662	10,661	10,661
Mill Creek 3	10,674	10,858	10,745	10,511	10,517	10,503	10,493	10,503	10,507	10,505	10,504	10,508	10,507	10,504	10,504	10,503	10,499	10,499
Mill Creek 4	10,836	10,388	10,497	10,414	10,419	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,296	12,561	13,159	13,197	13,187	13,161	13,221	13,243	13,260	13,277	13,270	13,266	13,262	13,251	13,247
Trimble County 1 (75%)	10,746	8,085	10,861	10,646	10,671	10,656	10,647	10,650	10,646	10,642	10,637	10,648	10,646	10,642	10,644	10,650	10,644	10,646
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,172	11,761	12,404	12,477	12,541	12,436	12,556	12,499	12,495	12,527	12,544	12,612	12,649	12,634	12,782
Trimble County 6	11,958	10,791	11,094	11,196	11,681	12,274	12,324	12,369	12,495	12,373	12,301	12,347	12,385	12,387	12,483	12,537	12,513	12,652
Trimble County 7	12,342	11,043	11,163	11,200	11,600	12,149	12,171	12,218	12,398	12,176	12,276	12,157	12,237	12,238	12,339	12,387	12,360	12,529
Trimble County 8	12,854	11,149	11,658	11,205	11,471	11,902	11,948	11,983	12,185	11,925	12,058	12,029	12,030	12,035	12,128	12,173	12,154	12,314
Trimble County 9	12,491	10,664	11,024	11,200	11,433	11,794	11,852	11,864	12,089	11,911	11,944	11,941	11,926	11,931	11,996	12,018	12,003	12,190
Trimble County 10	12,634	11,331	11,288	11,194	11,389	11,697	11,745	11,757	11,914	11,781	11,793	11,796	11,792	11,834	11,916	11,929	11,917	12,025
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - High Load																		
E.W. Brown 1	12,407	12,983	12,628	10,774	10,680	10,621	10,743	10,737	10,589	10,722	10,737	10,722	10,685	10,698	10,658	10,656	10,664	10,658
E.W. Brown 2	10,675	11,142	11,294	10,539	10,474	10,467	10,483	10,475	10,479	10,486	10,476	10,462	10,463	10,468	10,457	10,448	10,458	10,455
E.W. Brown 3	11,397	11,646	11,606	11,251	11,179	11,102	11,132	11,151	11,145	11,129	11,133	11,138	11,122	11,127	11,147	11,152	11,162	11,164
E.W. Brown 5	16,513	13,490	13,316	13,149	13,196	13,839	14,028	14,070	14,196	14,078	14,227	14,306	14,309	14,265	14,228	14,210	14,192	14,189
E.W. Brown 6	12,092	10,609	11,694	11,147	11,170	11,557	11,579	11,621	11,723	11,657	11,659	11,640	11,743	11,756	11,762	11,756	11,745	11,738
E.W. Brown 7	11,182	10,605	11,599	11,149	11,189	11,455	11,542	11,546	11,553	11,567	11,606	11,579	11,595	11,702	11,717	11,706	11,710	11,691
E.W. Brown 8	15,416	12,874	12,753	13,878	14,010	14,631	14,949	15,027	15,112	15,059	14,953	15,029	14,967	14,940	14,885	14,869	14,832	14,848
E.W. Brown 9	16,309	13,215	12,764	13,435	13,504	13,992	14,490	14,468	14,556	14,442	14,308	14,415	14,370	14,415	14,373	14,367	14,342	14,351
E.W. Brown 10	15,629	13,004	12,590	13,087	13,127	13,491	14,018	13,998	14,069	14,003	13,959	13,981	13,954	13,946	13,912	13,911	13,894	13,900
E.W. Brown 11	15,911	13,569	13,521	13,541	13,639	14,237	14,725	14,675	14,748	14,689	14,586	14,659	14,608	14,602	14,555	14,543	14,511	14,523
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	7,028	7,025	7,277	7,303	7,311	7,323	7,289	7,304	7,291	7,281	7,268	7,277	7,291	7,319	7,313
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,469	10,471	10,483	10,485	10,488	10,486	10,487	10,486	10,488	10,487	10,488	10,486	10,486	10,486	10,488
Ghent 2	10,688	10,629	10,335	10,344	10,351	10,348	10,345	10,347	10,338	10,342	10,345	10,346	10,349	10,344	10,347	10,351	10,351	10,350
Ghent 3	10,912	11,003	11,057	11,083	11,076	11,087	11,092	11,094	11,091	11,096	11,099	11,090	11,094	11,100	11,096	11,094	11,095	11,095
Ghent 4	10,912	10,930	10,835	10,783	10,786	10,793	10,805	10,802	10,796	10,804	10,805	10,797	10,794	10,796	10,802	10,793	10,794	10,795
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,453	10,466	10,456	10,444	10,452	10,454	10,452	10,457	10,463	10,467	10,463	10,463	10,463	10,467	10,466
Mill Creek 2	10,693	10,629	10,773	10,654	10,659	10,659	10,654	10,659	10,660	10,660	10,660	10,663	10,663	10,664	10,662	10,666	10,665	10,665
Mill Creek 3	10,674	10,858	10,745	10,513	10,519	10,507	10,497	10,506	10,511	10,509	10,509	10,512	10,512	10,509	10,509	10,509	10,505	10,505
Mill Creek 4	10,836	10,388	10,497	10,414	10,419	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,272	12,496	13,101	13,152	13,139	13,107	13,173	13,190	13,202	13,221	13,210	13,204	13,199	13,186	13,180
Trimble County 1 (75%)	10,746	8,085	10,861	10,653	10,677	10,662	10,654	10,657	10,654	10,651	10,647	10,658	10,657	10,653	10,655	10,662	10,656	10,659
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,150	11,707	12,329	12,408	12,473	12,363	12,469	12,418	12,408	12,432	12,443	12,511	12,550	12,537	12,665
Trimble County 6	11,958	10,791	11,094	11,173	11,630	12,201	12,256	12,303	12,421	12,290	12,217	12,261	12,291	12,288	12,380	12,435	12,412	12,531
Trimble County 7	12,342	11,043	11,163	11,177	11,550	12,078	12,108	12,155	12,327	12,101	12,199	12,068	12,149	12,144	12,242	12,291	12,265	12,407
Trimble County 8	12,854	11,149	11,658	11,181	11,431	11,842	11,896	11,931	12,125	11,865	11,996	11,961	11,959	11,958	12,046	12,090	12,072	12,197
Trimble County 9	12,491	10,664	11,024	11,176	11,396	11,736	11,802	11,815	12,032	11,848	11,883	11,880	11,858	11,855	11,916	11,938	11,922	12,071
Trimble County 10	12,634	11,331	11,288	11,170	11,353	11,643	11,700	11,712	11,862	11,724	11,735	11,733	11,728	11,761	11,834	11,848	11,834	11,916
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company

Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - Low Load																		
E.W. Brown 1	12,407	12,983	12,628	10,795	10,720	10,661	10,799	10,797	10,611	10,786	10,811	10,819	10,766	10,785	10,728	10,723	10,743	10,739
E.W. Brown 2	10,675	11,142	11,294	10,564	10,504	10,495	10,510	10,504	10,511	10,519	10,511	10,501	10,507	10,514	10,497	10,490	10,503	10,501
E.W. Brown 3	11,397	11,646	11,606	11,301	11,239	11,157	11,174	11,207	11,209	11,188	11,198	11,229	11,203	11,199	11,243	11,263	11,259	11,263
E.W. Brown 5	16,513	13,490	13,316	13,248	13,275	14,003	14,193	14,244	14,371	14,272	14,508	14,638	14,666	14,639	14,598	14,597	14,584	14,594
E.W. Brown 6	12,092	10,609	11,694	11,185	11,209	11,623	11,632	11,678	11,787	11,725	11,728	11,723	11,850	11,883	11,883	11,881	11,872	11,872
E.W. Brown 7	11,182	10,605	11,599	11,188	11,230	11,526	11,602	11,609	11,619	11,643	11,690	11,678	11,695	11,848	11,859	11,854	11,858	11,849
E.W. Brown 8	15,416	12,874	12,753	14,024	14,161	14,846	15,215	15,291	15,378	15,351	15,272	15,386	15,341	15,329	15,269	15,284	15,247	15,275
E.W. Brown 9	16,309	13,215	12,764	13,503	13,579	14,128	14,661	14,660	14,750	14,649	14,527	14,669	14,641	14,698	14,647	14,668	14,635	14,659
E.W. Brown 10	15,629	13,004	12,590	13,126	13,170	13,574	14,147	14,145	14,219	14,169	14,113	14,185	14,159	14,158	14,113	14,137	14,108	14,129
E.W. Brown 11	15,911	13,569	13,521	13,661	13,763	14,415	14,944	14,921	14,997	14,959	14,872	14,984	14,949	14,965	14,910	14,929	14,895	14,921
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	7,072	7,065	7,338	7,364	7,366	7,387	7,350	7,376	7,371	7,372	7,358	7,373	7,387	7,403	7,393
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,467	10,471	10,486	10,488	10,493	10,490	10,493	10,495	10,495	10,495	10,496	10,495	10,494	10,495	10,497
Ghent 2	10,688	10,629	10,335	10,339	10,347	10,344	10,340	10,342	10,332	10,336	10,337	10,339	10,341	10,336	10,339	10,343	10,342	10,342
Ghent 3	10,912	11,003	11,057	11,095	11,085	11,100	11,106	11,110	11,107	11,115	11,119	11,111	11,117	11,128	11,120	11,120	11,123	11,124
Ghent 4	10,912	10,930	10,835	10,792	10,797	10,806	10,822	10,820	10,810	10,823	10,829	10,820	10,816	10,819	10,830	10,816	10,819	10,820
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,441	10,456	10,445	10,432	10,440	10,442	10,439	10,442	10,447	10,450	10,445	10,446	10,444	10,449	10,447
Mill Creek 2	10,693	10,629	10,773	10,650	10,654	10,656	10,651	10,656	10,655	10,656	10,655	10,657	10,655	10,656	10,654	10,658	10,656	10,657
Mill Creek 3	10,674	10,858	10,745	10,508	10,515	10,500	10,489	10,499	10,503	10,501	10,499	10,502	10,501	10,498	10,498	10,496	10,492	10,492
Mill Creek 4	10,836	10,388	10,497	10,414	10,419	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	11,316	12,616	13,206	13,236	13,229	13,211	13,262	13,286	13,306	13,322	13,317	13,314	13,313	13,304	13,302
Trimble County 1 (75%)	10,746	8,085	10,861	10,639	10,664	10,648	10,640	10,642	10,638	10,633	10,628	10,637	10,635	10,631	10,632	10,638	10,631	10,634
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	11,192	11,812	12,473	12,542	12,603	12,507	12,639	12,577	12,579	12,618	12,638	12,704	12,741	12,725	12,894
Trimble County 6	11,958	10,791	11,094	11,217	11,728	12,341	12,387	12,430	12,562	12,452	12,385	12,432	12,475	12,481	12,580	12,633	12,610	12,769
Trimble County 7	12,342	11,043	11,163	11,222	11,645	12,215	12,230	12,276	12,464	12,249	12,349	12,246	12,322	12,328	12,431	12,477	12,451	12,648
Trimble County 8	12,854	11,149	11,658	11,227	11,507	11,957	11,997	12,032	12,239	11,983	12,117	12,096	12,099	12,109	12,207	12,252	12,233	12,430
Trimble County 9	12,491	10,664	11,024	11,222	11,467	11,848	11,899	11,911	12,141	11,973	12,002	12,001	11,992	12,004	12,073	12,095	12,081	12,309
Trimble County 10	12,634	11,331	11,288	11,217	11,422	11,746	11,788	11,800	11,964	11,836	11,848	11,857	11,856	11,906	11,995	12,008	11,997	12,135
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

Kentucky Utilities Company and Louisville Gas and Electric Company

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Scenario: Low Gas - Base Load																		
E.W. Brown 1	12,407	12,983	12,628	10,747	11,129	10,939	11,015	10,974	10,848	11,015	10,969	11,039	10,933	10,980	10,838	10,810	10,839	10,844
E.W. Brown 2	10,675	11,142	11,294	10,650	10,753	10,574	10,575	10,583	10,716	10,618	10,574	10,553	10,566	10,587	10,546	10,543	10,545	10,544
E.W. Brown 3	11,397	11,646	11,606	11,563	11,514	11,463	11,442	11,480	11,465	11,435	11,462	11,543	11,477	11,477	11,636	11,699	11,632	11,651
E.W. Brown 5	16,513	13,490	13,316	12,578	12,563	12,832	12,659	12,546	12,452	12,461	12,596	12,586	12,737	12,851	12,937	12,945	12,937	12,905
E.W. Brown 6	12,092	10,609	11,694	11,012	11,033	11,183	11,249	11,218	11,211	11,212	11,233	11,179	11,229	11,222	11,228	11,230	11,234	11,200
E.W. Brown 7	11,182	10,605	11,599	10,962	11,026	11,134	11,182	11,161	11,142	11,160	11,170	11,143	11,171	11,162	11,172	11,167	11,169	11,155
E.W. Brown 8	15,416	12,874	12,753	12,706	12,821	13,007	12,870	12,776	12,851	12,768	12,796	12,819	12,997	13,168	13,462	13,610	13,596	13,410
E.W. Brown 9	16,309	13,215	12,764	12,739	12,763	13,166	13,138	12,933	12,928	12,919	12,918	12,994	13,123	13,190	13,429	13,483	13,525	13,407
E.W. Brown 10	15,629	13,004	12,590	12,715	12,735	13,072	13,015	12,939	12,924	12,928	12,925	12,965	13,081	13,088	13,266	13,283	13,266	13,258
E.W. Brown 11	15,911	13,569	13,521	12,690	12,778	12,944	12,988	12,789	12,840	12,782	12,787	12,822	12,976	13,108	13,345	13,472	13,459	13,308
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,827	6,837	6,883	6,904	6,864	6,845	6,857	6,863	6,882	6,888	6,905	6,926	6,937	6,952	6,916
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,466	10,468	10,491	10,495	10,505	10,505	10,499	10,514	10,503	10,505	10,501	10,494	10,492	10,493	10,497
Ghent 2	10,688	10,629	10,335	10,322	10,334	10,332	10,329	10,334	10,317	10,327	10,327	10,328	10,330	10,328	10,330	10,336	10,335	10,336
Ghent 3	10,912	11,003	11,057	11,143	11,119	11,118	11,130	11,143	11,157	11,150	11,153	11,151	11,151	11,158	11,153	11,154	11,153	11,152
Ghent 4	10,912	10,930	10,835	10,831	10,841	10,827	10,836	10,849	10,868	10,852	10,853	10,834	10,833	10,824	10,828	10,808	10,810	10,818
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,393	10,420	10,421	10,407	10,411	10,409	10,416	10,414	10,423	10,424	10,425	10,424	10,425	10,428	10,430
Mill Creek 2	10,693	10,629	10,773	10,634	10,639	10,647	10,643	10,645	10,642	10,647	10,645	10,649	10,646	10,650	10,648	10,652	10,650	10,652
Mill Creek 3	10,674	10,858	10,745	10,489	10,500	10,483	10,470	10,478	10,482	10,482	10,480	10,491	10,492	10,482	10,482	10,479	10,477	10,478
Mill Creek 4	10,836	10,388	10,497	10,412	10,417	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	10,569	10,870	10,730	10,982	10,771	10,783	10,720	10,766	10,755	10,806	10,887	10,857	10,750	10,802	10,739
Trimble County 1 (75%)	10,746	8,085	10,861	10,586	10,622	10,618	10,614	10,610	10,592	10,603	10,602	10,610	10,607	10,608	10,606	10,611	10,607	10,611
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	10,845	11,065	11,046	11,150	11,099	11,078	11,076	11,116	11,083	11,101	11,092	11,100	11,094	11,108	11,059
Trimble County 6	11,958	10,791	11,094	10,875	11,077	11,077	11,179	11,130	11,076	11,108	11,125	11,114	11,133	11,122	11,129	11,126	11,135	11,088
Trimble County 7	12,342	11,043	11,163	10,902	11,054	11,109	11,181	11,152	11,084	11,142	11,178	11,128	11,169	11,152	11,159	11,156	11,162	11,119
Trimble County 8	12,854	11,149	11,658	10,925	11,082	11,141	11,203	11,186	11,115	11,179	11,208	11,146	11,201	11,182	11,188	11,186	11,188	11,150
Trimble County 9	12,491	10,664	11,024	10,946	11,105	11,167	11,245	11,226	11,152	11,197	11,236	11,175	11,233	11,210	11,215	11,212	11,213	11,181
Trimble County 10	12,634	11,331	11,288	10,958	11,101	11,213	11,271	11,255	11,181	11,227	11,264	11,226	11,252	11,237	11,240	11,237	11,235	11,211
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Scenario: Low Gas - High Load																		
E.W. Brown 1	12,407	12,983	12,628	10,741	11,087	10,929	10,999	10,952	10,843	10,994	10,944	11,009	10,901	10,950	10,808	10,782	10,810	10,809
E.W. Brown 2	10,675	11,142	11,294	10,638	10,736	10,561	10,567	10,573	10,702	10,605	10,562	10,535	10,548	10,570	10,528	10,522	10,527	10,522
E.W. Brown 3	11,397	11,646	11,606	11,531	11,485	11,441	11,428	11,464	11,443	11,415	11,445	11,524	11,452	11,455	11,603	11,663	11,598	11,619
E.W. Brown 5	16,513	13,490	13,316	12,548	12,538	12,798	12,643	12,527	12,437	12,437	12,570	12,554	12,702	12,809	12,893	12,896	12,887	12,854
E.W. Brown 6	12,092	10,609	11,694	10,993	11,015	11,157	11,225	11,190	11,182	11,180	11,199	11,142	11,192	11,186	11,192	11,195	11,200	11,160
E.W. Brown 7	11,182	10,605	11,599	10,947	11,009	11,112	11,164	11,140	11,121	11,136	11,146	11,113	11,143	11,134	11,147	11,141	11,143	11,126
E.W. Brown 8	15,416	12,874	12,753	12,688	12,795	12,983	12,847	12,757	12,832	12,741	12,777	12,791	12,971	13,135	13,401	13,529	13,512	13,334
E.W. Brown 9	16,309	13,215	12,764	12,714	12,736	13,139	13,124	12,912	12,898	12,890	12,891	12,965	13,094	13,163	13,383	13,428	13,461	13,352
E.W. Brown 10	15,629	13,004	12,590	12,692	12,711	13,044	13,000	12,915	12,891	12,898	12,900	12,934	13,044	13,058	13,219	13,237	13,217	13,206
E.W. Brown 11	15,911	13,569	13,521	12,674	12,757	12,921	12,979	12,769	12,822	12,758	12,767	12,794	12,945	13,072	13,284	13,396	13,381	13,237
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,827	6,835	6,878	6,898	6,862	6,843	6,853	6,859	6,876	6,880	6,894	6,913	6,921	6,931	6,903
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,464	10,468	10,489	10,493	10,501	10,501	10,495	10,507	10,499	10,499	10,497	10,490	10,489	10,489	10,493
Ghent 2	10,688	10,629	10,335	10,323	10,336	10,334	10,331	10,336	10,319	10,330	10,330	10,332	10,334	10,332	10,334	10,340	10,340	10,340
Ghent 3	10,912	11,003	11,057	11,135	11,112	11,110	11,122	11,135	11,148	11,139	11,142	11,136	11,137	11,143	11,138	11,136	11,137	11,134
Ghent 4	10,912	10,930	10,835	10,822	10,831	10,819	10,828	10,839	10,854	10,839	10,839	10,821	10,820	10,812	10,814	10,797	10,799	10,806
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,395	10,424	10,427	10,412	10,416	10,413	10,421	10,420	10,430	10,432	10,434	10,432	10,433	10,436	10,440
Mill Creek 2	10,693	10,629	10,773	10,632	10,640	10,648	10,644	10,646	10,643	10,649	10,647	10,652	10,650	10,654	10,652	10,657	10,655	10,657
Mill Creek 3	10,674	10,858	10,745	10,491	10,503	10,486	10,473	10,482	10,486	10,487	10,485	10,496	10,498	10,488	10,489	10,486	10,483	10,484
Mill Creek 4	10,836	10,388	10,497	10,412	10,417	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	10,554	10,832	10,710	10,956	10,749	10,763	10,697	10,736	10,725	10,772	10,850	10,819	10,713	10,766	10,705
Trimble County 1 (75%)	10,746	8,085	10,861	10,588	10,628	10,624	10,620	10,615	10,596	10,609	10,608	10,618	10,616	10,617	10,615	10,621	10,617	10,621
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	10,825	11,035	11,019	11,119	11,069	11,050	11,044	11,078	11,044	11,057	11,050	11,055	11,048	11,064	11,016
Trimble County 6	11,958	10,791	11,094	10,855	11,049	11,049	11,148	11,099	11,047	11,074	11,088	11,073	11,088	11,078	11,083	11,079	11,091	11,044
Trimble County 7	12,342	11,043	11,163	10,880	11,028	11,080	11,150	11,119	11,054	11,106	11,137	11,086	11,122	11,106	11,112	11,109	11,117	11,072
Trimble County 8	12,854	11,149	11,658	10,903	11,055	11,109	11,171	11,151	11,086	11,142	11,167	11,102	11,153	11,134	11,140	11,138	11,142	11,101
Trimble County 9	12,491	10,664	11,024	10,924	11,077	11,132	11,212	11,192	11,121	11,159	11,194	11,138	11,185	11,161	11,167	11,165	11,166	11,130
Trimble County 10	12,634	11,331	11,288	10,936	11,075	11,176	11,239	11,220	11,150	11,188	11,222	11,180	11,205	11,188	11,192	11,190	11,189	11,159
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch10

UNIT PERFORMANCE DATA (1)

Average Heat Rate (Btu/kWh)

	(ACTUAL)			(PROJECTED)														
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - Low Load																		
E.W. Brown 1	12,407	12,983	12,628	10,755	11,170	10,949	11,030	10,996	10,853	11,034	10,992	11,068	10,965	11,007	10,868	10,837	10,868	10,877
E.W. Brown 2	10,675	11,142	11,294	10,661	10,769	10,587	10,583	10,593	10,729	10,631	10,586	10,571	10,583	10,603	10,564	10,562	10,563	10,566
E.W. Brown 3	11,397	11,646	11,606	11,593	11,542	11,484	11,454	11,494	11,485	11,454	11,477	11,560	11,500	11,498	11,667	11,731	11,663	11,680
E.W. Brown 5	16,513	13,490	13,316	12,607	12,587	12,865	12,677	12,568	12,468	12,485	12,622	12,621	12,776	12,897	12,984	12,997	12,991	12,959
E.W. Brown 6	12,092	10,609	11,694	11,029	11,050	11,207	11,272	11,244	11,237	11,241	11,263	11,216	11,264	11,258	11,261	11,263	11,266	11,239
E.W. Brown 7	11,182	10,605	11,599	10,977	11,042	11,154	11,197	11,179	11,161	11,182	11,192	11,170	11,196	11,187	11,195	11,191	11,193	11,183
E.W. Brown 8	15,416	12,874	12,753	12,723	12,845	13,034	12,892	12,796	12,868	12,791	12,817	12,848	13,028	13,209	13,528	13,699	13,685	13,485
E.W. Brown 9	16,309	13,215	12,764	12,759	12,788	13,193	13,152	12,954	12,954	12,944	12,944	13,025	13,161	13,221	13,481	13,546	13,597	13,462
E.W. Brown 10	15,629	13,004	12,590	12,733	12,758	13,097	13,033	12,962	12,948	12,954	12,947	12,995	13,119	13,119	13,317	13,336	13,318	13,310
E.W. Brown 11	15,911	13,569	13,521	12,703	12,799	12,969	13,002	12,807	12,857	12,805	12,805	12,852	13,010	13,151	13,409	13,554	13,541	13,379
Cane Run 4	11,161	12,588	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 5	10,845	11,461	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 6	10,841	11,043	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cane Run 7	NA	6,980	6,733	6,827	6,839	6,887	6,909	6,866	6,848	6,860	6,867	6,887	6,897	6,917	6,942	6,955	6,976	6,929
Cane Run 11	(5,919)	56,474	(51,223)	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
Ghent 1	10,823	10,698	10,649	10,468	10,470	10,493	10,497	10,510	10,511	10,503	10,522	10,509	10,511	10,506	10,500	10,497	10,498	10,503
Ghent 2	10,688	10,629	10,335	10,321	10,332	10,330	10,327	10,332	10,316	10,326	10,325	10,325	10,326	10,324	10,326	10,331	10,331	10,331
Ghent 3	10,912	11,003	11,057	11,152	11,128	11,127	11,139	11,153	11,167	11,161	11,164	11,166	11,166	11,175	11,169	11,173	11,171	11,172
Ghent 4	10,912	10,930	10,835	10,842	10,853	10,837	10,846	10,860	10,884	10,868	10,868	10,849	10,848	10,840	10,846	10,822	10,824	10,834
Green River 3	12,961	13,074	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Green River 4	11,397	10,712	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Haefling 1-2 (2)	21,195	21,995	46,702	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
Mill Creek 1	10,464	10,470	10,539	10,391	10,415	10,416	10,403	10,407	10,405	10,410	10,407	10,415	10,416	10,417	10,416	10,417	10,420	10,421
Mill Creek 2	10,693	10,629	10,773	10,635	10,638	10,646	10,643	10,645	10,642	10,645	10,644	10,646	10,643	10,646	10,644	10,648	10,646	10,647
Mill Creek 3	10,674	10,858	10,745	10,488	10,498	10,479	10,467	10,474	10,477	10,478	10,476	10,485	10,486	10,476	10,476	10,473	10,471	10,472
Mill Creek 4	10,836	10,388	10,497	10,411	10,416	10,417	10,417	10,417	10,423	10,419	10,419	10,419	10,418	10,417	10,421	10,419	10,421	10,419
Paddy's Run 11&12	28,983	(13,051)	(46,690)	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242	16,242
Paddy's Run 13	11,145	10,809	10,921	10,586	10,910	10,749	11,005	10,793	10,803	10,743	10,795	10,785	10,841	10,922	10,895	10,788	10,838	10,773
Trimble County 1 (75%)	10,746	8,085	10,861	10,585	10,617	10,612	10,609	10,605	10,588	10,598	10,596	10,602	10,600	10,600	10,599	10,602	10,599	10,602
Trimble County 2 (75%)	9,300	6,919	10,155	9,178	9,176	9,187	9,186	9,187	9,187	9,187	9,185	9,187	9,187	9,187	9,187	9,187	9,187	9,187
Trimble County 5	12,985	11,056	11,200	10,866	11,094	11,071	11,179	11,128	11,105	11,108	11,154	11,122	11,145	11,134	11,146	11,140	11,152	11,102
Trimble County 6	11,958	10,791	11,094	10,896	11,104	11,103	11,208	11,160	11,104	11,142	11,162	11,154	11,179	11,166	11,175	11,173	11,181	11,134
Trimble County 7	12,342	11,043	11,163	10,923	11,080	11,136	11,211	11,184	11,112	11,177	11,217	11,172	11,216	11,198	11,205	11,204	11,209	11,167
Trimble County 8	12,854	11,149	11,658	10,946	11,107	11,170	11,233	11,218	11,144	11,214	11,248	11,190	11,248	11,229	11,234	11,233	11,235	11,200
Trimble County 9	12,491	10,664	11,024	10,967	11,131	11,199	11,276	11,258	11,181	11,235	11,277	11,211	11,280	11,259	11,261	11,259	11,259	11,233
Trimble County 10	12,634	11,331	11,288	10,979	11,126	11,247	11,303	11,287	11,211	11,266	11,305	11,272	11,299	11,285	11,286	11,283	11,282	11,264
Zorn 1	40,436	20,388	38,145	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676

(1) Combustion turbines to be reported as a composite facility.

(2) Haefling 1-2 actuals include Haefling 3

Kentucky Utilities Company and Louisville Gas and Electric Company

RENEWABLE RESOURCES (MWh)

Resource Type (1)	Unit Name	C.O.D.(2)	Build/ Purchase(3)	Life Duration(4)	Size MW (5)	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hydro	Dix Dam 1-3	11/01/1925	Built	2031+	32	72,287	97,943	78,642	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900	75,900
Hydro	Ohio Falls 1-8	01/01/1928	Built	2031+	60	271,888	273,775	316,437	263,569	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870	287,870
Solar	Brown Solar	06/09/2016	Built	2031+	8	NA	NA	11,091	19,627	19,497	19,390	19,327	19,226	19,208	19,174	19,077	18,943	18,864	18,757	18,777	18,645	18,525	18,462
Sub-total					100																		
Total Renewables					100																		

(1) Per definition of §56-576 of the code of Virginia.
(2) Commercial operation date.
(3) Describe as Company built or purchase.
(4) State expected life of facility or duration of purchase contract.
(5) Net dependable capability.

Kentucky Utilities Company and Louisville Gas and Electric Company
Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type(1)	Program Name	Date (2)	Life/ Duration(3)	Size MW (4)	(ACTUAL) 2006	2007	2008	2009	2010
Energy Efficiency	Residential Conservation Program	1998	2018	11	3,187	8,909	9,969	10,828	12,038
Energy Efficiency	WeCare	2001	2018	5	7,428	11,354	13,481	15,841	17,453
Energy Efficiency	Commercial Conservation/Rebates	1998	2018	156	13,227	17,510	19,469	21,720	53,938
Energy Efficiency	Residential High Efficiency Lighting	2009	2014	26	0	0	142	34,731	113,314
Energy Efficiency	Residential New Construction	2009	2014	6	0	0	0	360	4,441
Energy Efficiency	Residential HVAC Diagnostics & Tune Up	2009	2014	2	0	0	0	699	1,061
Energy Efficiency	Commercial HVAC Diagnostics & Tune Up	2009	2014	1	0	0	0	48	57
Energy Efficiency	Smart Energy Profile	2011	2018	20	0	0	0	0	0
Energy Efficiency	Residential Refrigerator Removal	2011	2018	5	0	0	0	0	0
Energy Efficiency	Residential Incentives	2011	2018	25	0	0	0	0	0
Energy Efficiency	KSBA	2013	2014	0	0	0	0	0	0
subtotal				**258**	**23,842**	**37,773**	**43,061**	**84,228**	**202,302**
Demand Response	Residential Demand Conservation	2008	2018	205	0	0	1,303	4,251	4,043
Demand Response	Commercial Demand Conservation	2008	2018	37	0	0	7	138	137
subtotal				**242**	**0**	**0**	**1,310**	**4,389**	**4,180**
Total				**500**	**23,842**	**37,773**	**44,371**	**88,616**	**206,482**

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand response/peak reduction. Additionally, in the notes provide a description of each.
(2) Implementation date.
(3) State expected life of facility or duration of purchase contract.
(4) Attributable capability and describe in the notes when such reductions are available (i.e. at peak, all hours, on-peak hours, etc.)
Note: Copy as needed for additional resources.

Kentucky Utilities Company and Louisville Gas and Electric Company
Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type(1)	Program Name	Date (2)	Life/ Duration(3)	Size MW (4)	(ACTUAL) 2011	2012	2013	2014	2015	2016
Energy Efficiency	Residential Conservation Program	1998	2018	11	14,049	16,008	23,352	26,801	32,006	40,381
Energy Efficiency	WeCare	2001	2018	5	20,411	22,865	25,487	29,829	37,240	44,947
Energy Efficiency	Commercial Conservation/Rebates	1998	2018	156	98,628	143,949	202,173	244,729	278,282	329,657
Energy Efficiency	Residential High Efficiency Lighting	2009	2014	26	214,217	259,532	308,501	345,520	345,520	345,520
Energy Efficiency	Residential New Construction	2009	2014	6	8,398	12,164	17,438	23,244	23,244	23,244
Energy Efficiency	Residential HVAC Diagnostics & Tune Up	2009	2014	2	1,798	2,511	3,396	3,609	3,609	3,609
Energy Efficiency	Commercial HVAC Diagnostics & Tune Up	2009	2014	1	114	119	123	123	123	123
Energy Efficiency	Smart Energy Profile	2011	2018	20	0	11,134	31,982	41,474	44,730	59,420
Energy Efficiency	Residential Refrigerator Removal	2011	2018	5	0	1,876	9,932	17,850	25,500	34,805
Energy Efficiency	Residential Incentives	2011	2018	25	0	8,505	32,587	57,219	77,753	102,084
Energy Efficiency	KSBA	2013	2014	0	0	0	12,312	16,577	24,623	5,569
subtotal				**258**	**357,615**	**478,663**	**667,282**	**806,974**	**892,630**	**989,359**
Demand Response	Residential Demand Conservation	2008	2018	205	4,043	4,043	4,043	4,043	4,043	4,043
Demand Response	Commercial Demand Conservation	2008	2018	37	137	137	137	137	137	137
subtotal				**242**	**4,180**	**4,180**	**4,180**	**4,180**	**4,180**	**4,180**
Total				**500**	**361,795**	**482,842**	**671,462**	**811,154**	**896,810**	**993,539**

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand response/peak reduction. Additionally, in the notes provide a description of each.

(2) Implementation date.

(3) State expected life of facility or duration of purchase contract.

(4) Attributable capability and describe in the notes when such reductions are available (i.e. at peak, all hours, on-peak hours, etc.)

Note: Copy as needed for additional resources.

Kentucky Utilities Company and Louisville Gas and Electric Company
Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type(1)	Program Name	Date (2)	Life/ Duration(3)	Size MW (4)	(PROJECTED) 2017	2018	2019	2020	2021	2022
Energy Efficiency	Residential Conservation Program	1998	2018	11	44,114	47,848	47,848	47,848	47,848	47,848
Energy Efficiency	WeCare	2001	2018	5	49,965	54,982	54,982	54,982	54,982	54,982
Energy Efficiency	Commercial Conservation/Rebates	1998	2018	156	373,163	416,668	416,668	416,668	416,668	416,668
Energy Efficiency	Residential High Efficiency Lighting	2009	2014	26	345,520	345,520	345,520	345,520	345,520	345,520
Energy Efficiency	Residential New Construction	2009	2014	6	23,244	23,244	23,244	23,244	23,244	23,244
Energy Efficiency	Residential HVAC Diagnostics & Tune Up	2009	2014	2	3,609	3,609	3,609	3,609	3,609	3,609
Energy Efficiency	Commercial HVAC Diagnostics & Tune Up	2009	2014	1	123	123	123	123	123	123
Energy Efficiency	Smart Energy Profile	2011	2018	20	59,663	59,663				
Energy Efficiency	Residential Refrigerator Removal	2011	2018	5	42,305	49,805	49,805	49,805	49,805	49,805
Energy Efficiency	Residential Incentives	2011	2018	25	105,652	109,220	109,220	109,220	109,220	109,220
Energy Efficiency	KSBA	2013	2014	0	8,043	8,494	902	902	902	902
subtotal				**258**	**1,055,401**	**1,119,177**	**1,051,922**	**1,051,922**	**1,051,922**	**1,051,922**
Demand Response	Residential Demand Conservation	2008	2018	205	4,043	4,043	4,043	4,043	4,043	4,043
Demand Response	Commercial Demand Conservation	2008	2018	37	137	137	137	137	137	137
subtotal				**242**	**4,180**	**4,180**	**4,180**	**4,180**	**4,180**	**4,180**
Total				**500**	**1,059,581**	**1,123,357**	**1,056,102**	**1,056,102**	**1,056,102**	**1,056,102**

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand response/peak reduction. Additionally, in the notes provide a description of each.
(2) Implementation date.
(3) State expected life of facility or duration of purchase contract.
(4) Attributable capability and describe in the notes when such reductions are available (i.e. at peak, all hours, on-peak hours, etc.)
Note: Copy as needed for additional resources.

Kentucky Utilities Company and Louisville Gas and Electric Company
Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type(1)	Program Name	Date (2)	Life/ Duration(3)	Size MW (4)	(PROJECTED) 2023	2024	2025	2026
Energy Efficiency	Residential Conservation Program	1998	2018	11	47,848	47,848	47,848	47,848
Energy Efficiency	WeCare	2001	2018	5	54,982	54,982	54,982	54,982
Energy Efficiency	Commercial Conservation/Rebates	1998	2018	156	416,668	416,668	416,668	416,668
Energy Efficiency	Residential High Efficiency Lighting	2009	2014	26	345,520	345,520	345,520	345,520
Energy Efficiency	Residential New Construction	2009	2014	6	23,244	23,244	23,244	23,244
Energy Efficiency	Residential HVAC Diagnostics & Tune Up	2009	2014	2	3,609	3,609	3,609	3,609
Energy Efficiency	Commercial HVAC Diagnostics & Tune Up	2009	2014	1	123	123	123	123
Energy Efficiency	Smart Energy Profile	2011	2018	20				
Energy Efficiency	Residential Refrigerator Removal	2011	2018	5	49,805	49,805	49,805	49,805
Energy Efficiency	Residential Incentives	2011	2018	25	109,220	109,220	109,220	109,220
Energy Efficiency	KSBA	2013	2014	0	902	902	902	902
subtotal				**258**	**1,051,922**	**1,051,922**	**1,051,922**	**1,051,922**
Demand Response	Residential Demand Conservation	2008	2018	205	4,043	4,043	4,043	4,043
Demand Response	Commercial Demand Conservation	2008	2018	37	137	137	137	137
subtotal				**242**	**4,180**	**4,180**	**4,180**	**4,180**
Total				**500**	**1,056,102**	**1,056,102**	**1,056,102**	**1,056,102**

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand response/peak reduction. Additionally, in the notes provide a description of each.
(2) Implementation date.
(3) State expected life of facility or duration of purchase contract.
(4) Attributable capability and describe in the notes when such reductions are available (i.e. at peak, all hours, on-peak hours, etc.)

Note: Copy as needed for additional resources.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch13

UNIT PERFORMANCE DATA (1)

Unit Size (MW) Uprate and Derate

	(ACTUAL)			(PROJECTED)														
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
E.W. Brown 1																		
E.W. Brown 2																		
E.W. Brown 3			-1															
E.W. Brown 5		-3																
E.W. Brown 6																		
E.W. Brown 7																		
E.W. Brown 8																		
E.W. Brown 9																		
E.W. Brown 10																		
E.W. Brown 11																		
E.W. Brown Solar			8															
Cane Run 4		-155																
Cane Run 5		-168																
Cane Run 6		-240																
Cane Run 7		642	20															
Cane Run 11																		
Dix Dam 1-3		1.5																
Ghent 1		-5																
Ghent 2			-2															
Ghent 3	-6	-4																
Ghent 4		-4																
Green River 3		-68																
Green River 4		-93																
Haefling 1-3																		
Mill Creek 1		-3																
Mill Creek 2		-4																
Mill Creek 3																		
Mill Creek 4																		
Ohio Falls 1	2																	
Ohio Falls 2			2															
Ohio Falls 3																		
Ohio Falls 4				2														
Ohio Falls 5																		
Ohio Falls 6																		
Ohio Falls 7																		
Ohio Falls 8				2														
Paddy's Run 11																		
Paddy's Run 12																		
Paddy's Run 13																		
Trimble County 1 (75%)			-13															
Trimble County 2 (75%)																		
Trimble County 5		2																
Trimble County 6		2																
Trimble County 7		2																
Trimble County 8		2																
Trimble County 9		2																
Trimble County 10		2																
Tyrone 3																		
Zorn 1																		

(1) Combustion turbines to be reported as composite facility.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch14

UNIT PERFORMANCE DATA (1)

Existing Supply-side Resource (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
E.W. Brown 1	Harrodsburg, KY	Steam	Coal	05/01/1957	106
E.W. Brown 2	Harrodsburg, KY	Steam	Coal	06/01/1963	166
E.W. Brown 3	Harrodsburg, KY	Steam	Coal	07/01/1971	409
E.W. Brown 5	Harrodsburg, KY	Turbine	Gas	06/08/2001	130
E.W. Brown 6	Harrodsburg, KY	Turbine	Gas	08/11/1999	146
E.W. Brown 7	Harrodsburg, KY	Turbine	Gas	08/08/1999	146
E.W. Brown 8	Harrodsburg, KY	Turbine	Gas	02/01/1995	121
E.W. Brown 9	Harrodsburg, KY	Turbine	Gas	08/01/1994	121
E.W. Brown 10	Harrodsburg, KY	Turbine	Gas	12/01/1995	121
E.W. Brown 11	Harrodsburg, KY	Turbine	Gas	05/01/1996	121
E.W. Brown Solar	Harrodsburg, KY	Solar PV	Solar	06/09/2016	8
Cane Run 7	Louisville, KY	Turbine	Gas	06/19/2015	662
Cane Run 11	Louisville, KY	Turbine	Gas	06/01/1968	14
Dix Dam 1-3	Harrodsburg, KY	Hydro	Hydro	11/01/1925	32
Ghent 1	Ghent, KY	Steam	Coal	02/01/1974	474
Ghent 2	Ghent, KY	Steam	Coal	04/01/1977	493
Ghent 3	Ghent, KY	Steam	Coal	05/01/1981	485
Ghent 4	Ghent, KY	Steam	Coal	08/01/1984	465
Haefling 1-2	Lexington, KY	Turbine	Gas	10/01/1970	24
Mill Creek 1	Louisville, KY	Steam	Coal	08/01/1972	300
Mill Creek 2	Louisville, KY	Steam	Coal	07/01/1974	297
Mill Creek 3	Louisville, KY	Steam	Coal	08/01/1978	391
Mill Creek 4	Louisville, KY	Steam	Coal	09/01/1982	477
Ohio Falls 1-8	Louisville, KY	Hydro	Hydro	01/01/1928	60
Paddy's Run 11	Louisville, KY	Turbine	Gas	06/01/1968	12
Paddy's Run 12	Louisville, KY	Turbine	Gas	07/01/1968	23
Paddy's Run 13	Louisville, KY	Turbine	Gas	06/27/2001	147
Trimble County 1 (75%)	Bedford, KY	Steam	Coal	12/23/1990	370
Trimble County 2 (75%)	Bedford, KY	Steam	Coal	01/22/2011	549
Trimble County 5	Bedford, KY	Turbine	Gas	05/14/2002	159
Trimble County 6	Bedford, KY	Turbine	Gas	05/14/2002	159
Trimble County 7	Bedford, KY	Turbine	Gas	06/01/2004	159
Trimble County 8	Bedford, KY	Turbine	Gas	06/01/2004	159
Trimble County 9	Bedford, KY	Turbine	Gas	07/01/2004	159
Trimble County 10	Bedford, KY	Turbine	Gas	07/01/2004	159
Zorn 1	Louisville, KY	Turbine	Gas	05/01/1969	14

(1) Combustion turbines to be reported as a composite facility.

(2) Commercial operation date.

(3) Peak net dependable capability as of filing.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch15

UNIT PERFORMANCE DATA (1)

Planned Supply-side Resource (MW)

Scenario: Mid Gas - Base Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: Mid Gas - High Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: Mid Gas - Low Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: High Gas - Base Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: High Gas - High Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: High Gas - Low Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: Low Gas - Base Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: Low Gas - High Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

Scenario: Low Gas - Low Load

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D. (2)	Size MW (3)
NA	NA	NA	NA	NA	NA

(1) Combustion turbines to be reported as a composite facility.

(2) Commercial operation date.

(3) Peak net dependable capability as of filing.

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)															
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Base Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - High Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Mid Gas - Low Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - Base Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - High Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: High Gas - Low Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - Base Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - High Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch16

UNIT CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Scenario: Low Gas - Low Load																		
Existing Capacity																		
Conventional (1)	8,124	8,187	8,185	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Renewable	88	90	100	100	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total Existing Capacity	8,212	8,276	8,284	8,414	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Planned Capacity Changes																		
Conventional (2)	0	0	0	0	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Capacity Changes	0	0	0	4	0	-165	0	0	0	0	0	0	0	0	0	0	0	0
Expected New Capacity																		
Conventional	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unforced Availability	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Generation Capacity	8,212	8,276	8,284	8,418	8,418	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253	8,253
Existing DSM Reductions																		
Demand response	0	0	0	116	124	128	128	128	128	128	128	128	128	128	128	128	128	128
Conservation/Efficiency	0	0	0	215	254	255	236	236	236	236	236	236	236	236	236	236	236	236
Total Existing DSM Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Expected New DSM Reductions																		
Demand response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expected New DSM Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand-side Reductions	0	0	0	331	378	383	364	364	364	364	364	364	364	364	364	364	364	364
Net Generation & Demand-side	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617
Capacity Requirement or PJM Capacity Obligation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Utility Capacity Position	8,212	8,276	8,284	8,750	8,796	8,637	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617	8,617

(1) Existing Capacity for conventional resources includes Curtailable Service Rider customers.

(2) Planned Capacity Changes for conventional resources include updates to unit rating assumptions.

2017 IRP

ıtucky Utilities Company Sch17

ꞩSTRUCTION FORECAST (Million Dollars)

	ACTUAL EXPENDITURES (1)			PROJECTED EXPENDITURES (2)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ɜw Traditional Generating Facilities																		
apital Investment (Exclusive of AFUDC)	0	0	0	260	345	245	187	192	0	0	0	0	0	0	0	0	0	0
FUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nnual Total	0	0	0	260	345	245	187	192	0	0	0	0	0	0	0	0	0	0
umulative Total	0	0	0	260	605	850	1037	1229	1229	1229	1229	1229	1229	1229	1229	1229	1229	1229
ew Renewable Generating Facilities																		
apital Investment (Exclusive of AFUDC)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nnual Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
umulative Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
)ther Facilites																		
ransmission	40	39	68	109	112	126	113	113	0	0	0	0	0	0	0	0	0	0
istribution	72	55	84	109	116	120	109	108	0	0	0	0	0	0	0	0	0	0
nergy conservation/efficiency & demand response	705	933	119	69	106	94	32	27	0	0	0	0	0	0	0	0	0	0
FUDC	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nnual Total	817	1,027	271	287	334	340	254	248	-	-	-	-	-	-	-	-	-	-
ımulative Total	817	1,845	2,115	287	621	961	1215	1463	1463	1463	1463	1463	1463	1463	1463	1463	1463	1463
Total Construction Expenditures																		
nnual	817	1,027	271	547	679	585	441	440	0	0	0	0	0	0	0	0	0	0
umulative	817	1,845	2,115	547	1226	1811	2252	2692	2692	2692	2692	2692	2692	2692	2692	2692	2692	2692
'ercent of Funds for Total Construction rovided from External Financing (3)	38%	46%	46%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

\ctual expenses for 2014-2016 include generation, distribution, transmission, environmental, and other capital projects

This information is provided for 2017-2021 and primarily represents major generation and environmental projects at the Cane Run, Trimble County, Green River, and E.W. Brown facilities

Represents year ending total debt divided by total capitalization

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

Scenario: Mid Gas - Base Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu) (1)																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

Scenario: Mid Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company

Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

Scenario: Mid Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

Scenario: High Gas - Base Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

Scenario: High Gas - High Load

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

Scenario: High Gas - Low Load

	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

Kentucky Utilities Company and Louisville Gas and Electric Company | Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

Scenario: Low Gas - Base Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

Scenario: Low Gas - High Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

2017 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch18

FUEL DATA — CONFIDENTIAL INFORMATION REDACTED

Scenario: Low Gas - Low Load	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Delivered Fuel Price (cents/MBtu)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas (2)																		
f. Renewable (3)																		
Primary Fuel Expenses (cents/kWh)*																		
a. Nuclear	[redacted]			[redacted]														
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable (3)																		
g. Purchases Energy Charges Only																		
h. Purchases Energy and Capacity Charges																		

(1) To reflect total dispatch costs, including any variable operating, maintenance, and environmental or compliance costs.

(2) Reflects Henry Hub natural gas price.

(3) Per definition of §56-576 of the Code of Virginia.