a PPL company



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*VIA OVERNIGHT DELIVERY*

April 28, 2016

**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. PUE-2016-00053**

Dear Mr. Peck:

Pursuant to §56-597 of the Code of Virginia, 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 Virginia State Corporation Commission's ("Commission") 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.

Mr. Joel H. Peck, Clerk
April 28, 2016

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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)
Kimberly B. Pate, Director, Division of Utility Accounting & Finance (w/encl.)
William F. Stephens, Director, Division of Energy Regulation (w/encl.)
Delegate Terry G. Kilgore, Chairman, House Committee on Commerce and Labor (w/encl.)
Senator John C. Watkins, 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

# ODP
# 2016 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
# 2016 VA IRP SUMMARY

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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. 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.

# ODP
# 2016 VA IRP SUMMARY



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 forthcoming federal Clean Power Plan.

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 500 MW and cumulative energy savings of 1.6 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 forthcoming federal Clean Power Plan, regardless of the amount of energy efficiency ODP's customers are able to achieve.

# ODP
# 2016 VA IRP SUMMARY

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, and a new 10MW solar photovoltaic facility, 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.

# ODP
# 2016 VA IRP SUMMARY

Additional information is available in the Exhibits noted below.

- Exhibit 1 – Clean Power Plan Status
- Exhibit 2 – Environmental Regulations
- Exhibit 3 – 2015 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.

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Exhibit 1

## Clean Power Plan Status – ODP

The VSCC stated in its Final Order concerning KU/ODP's 2015 IRP:

> Furthermore, while we find that KU/ODP's IRP is reasonable and in the public interest for the purposes set forth herein, we also find that additional analysis of several areas should be required in future filings. We recognize that the U.S. Supreme Court's stay of the implementation of the CPP [Clean Power Plan] went into effect after KU/ODP filed its comments on the Staff Report, and this stay may further affect the steps taken in Kentucky regarding the electric generating units located therein. 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'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 state implementation plan.[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-

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[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-2015-00037, Order at 5-6 (Mar. 14, 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.

specific rate-based and mass-based reduction goals and guidelines for the development, 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] The EPA has not ruled on Kentucky's petition.

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."[11] The comments further asked the EPA to withdraw the proposed federal plan.[12]

The same day, Kentucky announced it would be seeking a two-year extension of the deadline to file a state compliance plan.[13] 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.

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[9] *Available at* http://eec.ky.gov/Documents/December%2021%20Petition%20for%20Reconsideration%20of%20111(d).pdf.
[10] *Id.*
[11] *Available at* http://air.ky.gov/SiteCollectionDocuments/GreenhouseGasEmissions_FederalPlanRequirements_Comments.pdf.
[12] *Id.*
[13] *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.[14] 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.[15]

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."[16] 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.[17] 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.[18]

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

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[14] *See* http://www.ago.wv.gov/publicresources/epa/Documents/Final%20States%20SCOTUS%20Stay%20App%20-%20ACTUAL%20%28M0116774xCECC6%29.pdf.

[15] *West Virginia v. Environmental Protection Agency*, No. 15-1363 (D.C. Cir.), *stay granted* (U.S. Feb. 9, 2016) (No. 15A776).

[16] *Available at* http://eec.ky.gov/Lists/News%20Releases%202/Energy%20and%20Environment%20Cabinet%20defers%20listening%20sessions%20after%20Supreme%20Court%20decision.pdf.

[17] *Available at* http://www.mcconnell.senate.gov/public/?a=Files.Serve&File_id=6AB51ED1-3638-4442-85B0-3C56D721861B

[18] *Id.* at 1-2.

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.

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# Exhibit 2

## 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 local, Kentucky, 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 Virginia agency during the Companies' National Pollution Discharge Elimination System ("NPDES") permit renewal process.

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

After ongoing study of the issue, in 2009 EPA determined it would revise the steam-electric industry effluent standards. In June 2010, EPA issued a detailed questionnaire to over 500 utilities across the nation aimed at assisting EPA to revise the standards. 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.

**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.

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.

**$NO_x$ 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

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

regulation to replace CAIR.[2] The CAIR $NO_x$ reduction program began in 2009 and the $SO_2$ program began in 2010 and included a Phase II beginning in 2015 to further reduce $NO_x$ 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 $NO_x$ and $SO_2$, with less reduction of $NO_x$ 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 continue to administer CAIR until EPA completed and promulgated necessary revisions to CSAPR.

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[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.").

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 with a final decision expected in the spring of 2014. 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 December 3, 2015, the EPA published in the Federal Register their proposed CSAPR Update Rule to further reduce ozone season $NO_x$ emissions from fossil-fired electric generating units beginning in 2017. The reduction of ozone season $NO_x$ allocations for the Companies associated with the proposed rule are approximately 30% below the current CSAPR allocations. The Companies timely submitted comments to the EPA concerning the proposed 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. With consideration that the CAIR rule was remanded, final approval is pending based on the outcome of re-instatement or replacement of the CSAPR rule as described above.

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 NOx 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, it is expected that EPA will issue some associated discussion of using the CSAPR transport emissions reduction program for demonstration of compliance with the BART visibility regulations.

### 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 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 are completing 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 will utilize additives to assist with mercury removal and combine their emissions with the emissions of E.W. Brown Unit 3. Dry sorbent injection systems are being installed on each unit that receives a PJFF system for the purpose of protecting the materials of construction. PAC injection systems are being 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 are being tested at locations within the Companies' system. The use of these additives could allow for mercury control with reduced or no use of PAC.

As a result of positive effects from testing the liquid additives are being added to the Title V permits for all of our coal-fired facilities.

### National Ambient Air Quality Standards

#### *$SO_2$*

The EPA has 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. Kentucky must submit a SIP that contains enforceable emission limitations or control measures on sources contributing to non-attainment by April 2015 in order to achieve attainment by October 2018. The KDAQ has not completed the SIP revision to date but has indicated that air dispersion modeling performed in support of that effort has 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.

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. A preliminary air dispersion modeling effort has indicated the areas near both facilities are in attainment with the NAAQS. The modeling protocol was submitted accordingly by the Companies and is currently under evaluation by the EPA.

***$NO_2$***

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.

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.

Kentucky must incorporate this new NAAQS into its SIP. Additionally, the SIP must contain a plan to bring any non-attainment areas into attainment with the standard by June 2017.

***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, with plans for the final rule in the fall of 2015. The final regulation establishing the new standard at 0.070 ppm was published in the Federal Register on October 26, 2015. Kentucky will have 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.

***PM / $PM_{2.5}$***

EPA promulgated in December 2012 a new NAAQS for $PM_{2.5}$ 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 Louisville Metropolitan Air Pollution Control District ("LMAPCD"). Although Jefferson County is still currently 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.

In March 2015, EPA published designations of unclassifiable for Jefferson County and attainment/unclassifiable 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 2014 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 2012 standard to satisfy the attainment status of the 1997 standard, considering the 2012 standard is more restrictive.

**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.

**EXHIBIT 2**



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.

**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 are being developed.

part 2

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Exhibit 3

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# 2016 Resource Assessment

PPL companies

May 2016

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# 1 Executive Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") filed their 2015 Integrated Resource Plan ("IRP") with the Virginia State Corporation Commission on July 1, 2015. 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 have developed high-level ELG compliance costs, but more detailed estimates will not be available for 12 to 18 months. The future of the CPP is particularly 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. If the CPP is ultimately upheld and the staying of the CPP is held to delay the implementation of the rule by two years, compliance with the CPP will not begin until January 2024.

When more information is known regarding the costs and implementation of the CPP and ELG, the Companies will conduct a detailed study to determine the most cost-effective compliance plan. Given the extended compliance deadlines, this resource assessment assumes – in the absence of better information – 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 expansion 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 is reviewed, re-evaluated, and assessed against other available market alternatives prior to commitment and implementation.

The Companies' Resource Assessment was completed in three parts. First, the Companies developed a forecast of peak demand and energy requirements to assess the need for additional generating capacity. Next, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Then, this subset of generation technology options was incorporated into a detailed expansion planning analysis to determine the optimal expansion plans.

## 1.1 Capacity and Energy Need

Table 1 details the Companies' current capacity supply/demand balance for the 15-year planning period.[1] 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, "Planned/Proposed Resources" reflects the addition of the Brown Solar facility, which is expected to be commissioned in May 2016. The Bluegrass Agreement (165 MW) is included in "Firm Purchases" along with the Companies' share of Ohio Valley Electric Corporation ("OVEC") (152 MW). Considering these changes to the Companies' generation portfolio, along with 480 MW of demand reduction from DSM programs by 2018, and 136 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning in 2029.

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

**Table 1 – Resource Summary (MW, Summer)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| Forecast Peak Load | 7,356 | 7,430 | 7,485 | 7,234 | 7,234 | 7,457 | 7,485 | 7,513 |
| DSM | (408) | (442) | (481) | (490) | (480) | (480) | (480) | (480) |
| Net Peak Load | 6,948 | 6,988 | 7,004 | 6,744 | 6,754 | 6,977 | 7,005 | 7,033 |
| | | | | | | | | |
| Existing Resources[2] | 7,815 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 |
| Planned/Proposed Resources[3] | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Firm Purchases[4] | 317 | 317 | 317 | 152 | 152 | 152 | 152 | 152 |
| Curtailable Load | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| Total Supply | 8,276 | 8,280 | 8,280 | 8,115 | 8,115 | 8,115 | 8,115 | 8,115 |
| | | | | | | | | |
| Reserve Margin ("RM") | 19.1% | 18.5% | 18.2% | 20.3% | 20.1% | 16.3% | 15.8% | 15.4% |
| | | | | | | | | |
| RM Shortfall (16% RM) * | 216 | 174 | 155 | 292 | 280 | 21 | (11) | (43) |

*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, energy requirements are forecast to grow by 0.13 TWh over the next 15 years even after reductions for DSM and the municipal contract termination.[5] This translates into a compound annual growth rate of 0.03 percent.

**Table 2 – Energy Requirements (TWh, After DSM)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| Energy Requirements | 35.4 | 35.6 | 35.7 | 34.8 | 34.4 | 35.3 | 35.4 | 35.6 |

## 1.2 Supply-Side Screening Analysis

Over the past several years, resource costs have been generally stable due to the economic slow-down that began in 2008. An abundance of low cost natural gas supply resulting from advancements in natural gas drilling technologies coupled with relatively low capital and operating costs have greatly improved the economics of NGCC technology. Overall, the costs of renewable generation remain higher than fossil generation technologies. However, with tax incentives and Renewable Energy Credits ("RECs"), both solar PV and wind technologies can be cost competitive.

In the screening analysis, the levelized cost 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 unit efficiency. As a result, the technology options were evaluated over 270 cases. Given the uncertainty in REC prices and

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[2] Existing resources include the retirement of Tyrone 3 in February 2013, Cane Run 6 in March 2015, Cane Run 4-5 in June 2015, and Green River 3-4 in September 2015, as well as the addition of Cane Run 7 in June 2015.

[3] Planned/Proposed Resources include Brown Solar in May 2016. 80% of the capacity of Brown Solar is assumed to be available at the time of peak.

[4] 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.

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

the availability of investment tax credits ("ITC") for renewable technologies, two iterations of 270 cases were evaluated:

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10% ITC and RECs: This iteration incorporated a 10% ITC and REC market prices for solar and wind technologies.

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. In the "No ITC or RECs" iteration, the "2x1 NGCC G/H-Class" option was least-cost in 212 of the 270 cases and ranked among the top four least-cost options in all 270 cases. The option to install three F-Class Simple-Cycle Combustion Turbines ("SCCTs") ("SCCT F-Class – Three Units") was least-cost in 58 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. In the "10% ITC and RECs" iteration, the solar PV and wind technology options were ranked among the top four least-cost technology options in multiple cases.

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

| Generation Technology Option | No ITC or RECs | | | | | 10% ITC and RECs | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | # Occurrences | | | | Total | # Occurrences | | | | Total |
| | 1st | 2nd | 3rd | 4th | | 1st | 2nd | 3rd | 4th | |
| 2x1 NGCC G/H-Class | 212 | 5 | 21 | 32 | **270** | 205 | 15 | 22 | 19 | **261** |
| 2x1 NGCC G/H-Class – DF | 0 | 86 | 184 | 0 | **270** | 0 | 65 | 195 | 10 | **270** |
| 2x1 NGCC F-Class | 0 | 149 | 51 | 17 | **217** | 0 | 156 | 37 | 18 | **211** |
| 2x1 NGCC F-Class – DF | 0 | 0 | 0 | 155 | **155** | 0 | 0 | 0 | 133 | **133** |
| SCCT F-Class – Three Units | 58 | 2 | 10 | 7 | **77** | 55 | 1 | 8 | 3 | **67** |
| SCCT F-Class – One Unit | 0 | 28 | 4 | 21 | **53** | 0 | 27 | 1 | 21 | **49** |
| 1x1 NGCC G/H-Class | 0 | 0 | 0 | 38 | **38** | 0 | 0 | 2 | 54 | **56** |
| Wind | 0 | 0 | 0 | 0 | **0** | 1 | 6 | 4 | 2 | **13** |
| Solar Photovoltaic | 0 | 0 | 0 | 0 | **0** | 9 | 0 | 1 | 1 | **11** |
| Compressed Air Energy Storage | 0 | 0 | 0 | 0 | **0** | 0 | 0 | 0 | 9 | **9** |

Table 4 lists the generation technology options that were evaluated in the detailed expansion planning analysis. The two F-Class NGCC options, the 2x1 NGCC G/H-Class option with duct firing ("DF"), and the Compressed Air Energy Storage ("CAES") option in Table 3 were ultimately excluded from the detailed analysis. Potential greenhouse gas ("GHG") regulations and uncertainty in gas prices make the added efficiency of the G-Class option more cost-effective than the F-Class option. Additionally, the capital and fixed costs for the G-Class option are lower on a per-kilowatt ("kW") basis. The 2x1 NGCC G/H-Class option with DF was consistently less favorable than the 2x1 NGCC G/H-Class option without duct firing.[6] The CAES option was eliminated because it ranked among the top four least-cost options in only ten or fewer of 270 cases. In addition, the Companies are not aware of any viable sites for CAES capacity near their service territories.

[6] In addition, the 2x1 NGCC options with duct firing are not materially different from the 2x1 NGCC options without duct firing. Duct firing serves as a means to adjust the size and flexibility of a NGCC unit.

**Table 4 – List of Technology Options Evaluated in Expansion Planning Analysis**

| 2014 IRP Generation Technology Options |
|---|
| 2x1 NGCC G/H-Class |
| 1x1 NGCC G/H-Class |
| SCCT F-Class – Three Units |
| SCCT F-Class – One Unit |
| Solar Photovoltaic |
| Wind |

The list of generation technology options in Table 4 is identical to the list of technology options that passed the screening analysis for the 2015 IRP.

## 1.3 Expansion Planning Analysis

In the expansion planning analysis, the Companies developed optimal expansion plans using the technology options in Table 4 over multiple natural gas price and load scenarios. The cost and unit characteristics for these technology options are summarized in Table 5. The NGCC technology options have higher capital and fixed operating and maintenance ("O&M") costs, but much better heat rates than SCCTs. The "SCCT F-Class – Three Units" option takes advantage of economies of scale, which results in lower capital costs on a dollar per kilowatt ("$/kW") basis. Wind and solar options have much higher capital costs than other options on a $/kW basis, but no energy costs.

**Table 5 – Cost and Unit Characteristics for Generation Technology Options (2013 $)**

| Generation Technology Option | 2x1 NGCC G/H-Class | 1x1 NGCC G/H-Class | SCCT F-Class – One Unit | SCCT F-Class – Three Units | Wind Turbine | Solar PV |
|---|---|---|---|---|---|---|
| Reference Name[7] | 2x1G | 1x1G | SCCT | CTx3 | Wind | SLPV |
| Net Capability (MW) | | | | | | |
| Summer | 737 | 368 | 201 | 602 | 50 | 50 |
| Winter | 859 | 429 | 220 | 659 | 50 | 50 |
| Overnight Installed Cost ($/kW)[8] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Non-Fuel Variable O&M ($/MWh)[9] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Fixed O&M ($/kW-yr)[10] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Full Load Heat Rate (mmBtu/MWh) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Unavailability (%)[11] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

The results of the expansion planning analysis are summarized in Table 6. The Companies have a long-term need for capacity beginning in 2029 in the Base load scenario and 2021 in the High load scenario.[14] In five of six Base and High load scenarios, this need was met with NGCC capacity; in one scenario, this need was met with SCCT capacity. In the Low load scenario, the Companies do not have a long-term need for capacity in the study period. Based on the results in Table 6, a natural gas unit will likely be included in the Companies' least-cost plan to reliably meet load requirements in the future.

[7] Reference names are abbreviated names for each generation technology option.
[8] Installed cost is based on annual average capacity.
[9] Variable O&M for NGCC and SCCT options includes long-term service agreement costs.
[10] Fixed O&M for NGCC and SCCT options includes costs associated with reserving firm gas-line capacity.
[11] Unavailability for NGCC and SCCT options is the long-term steady-state outage rate expected after initial operation. For wind and solar options, unavailability reflects the expected capacity factor (Unavailability = 1 – Capacity Factor).
[12] Wind turbine capacity factor modeled at 27% with 11% of the capacity counting toward reserve margin.
[13] Solar photovoltaic capacity factor modeled at 17.4% with 80% of the capacity counting toward reserve margin.
[14] The analysis assumed additional capacity cannot be added prior to 2021. For this reason, additional capacity is needed in 2021 in the High load scenario.

## Table 6 – Optimal Expansion Plans[15]

| Load | LL | LL | LL | BL | BL | BL | HL | HL | HL |
|---|---|---|---|---|---|---|---|---|---|
| Gas Price | LG | MG | HG | LG | MG | HG | LG | MG | HG |
| 2016 | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS |
| 2017 | | | | | | | | | |
| 2018 | | | | | | | | | |
| 2019 | | | | | | | | | |
| 2020 | | | | | | | | | |
| 2021 | | | | | | | 2x1G( 1) | 2x1G( 1) | 2x1G( 1) |
| 2022 | | | | | | | | | |
| 2023 | | | | | | | | | |
| 2024 | | | | | | | | | |
| 2025 | | | | | | | | | |
| 2026 | | | | | | | | | |
| 2027 | | | | | | | | | |
| 2028 | | | | | | | | | |
| 2029 | | | | 2x1G( 1) | 2x1G( 1) | SCCT( 1) | | | |
| 2030 | | | | | | | | | |

Load: Low (LL), Base (BL), High (HL)    Gas Price: Low (LG), Mid (MG), High (HG)



[15] In Table 6, the value in parentheses following the technology option's reference name indicates the number of units added in a given year.

## 2 Existing and Planned Generating Resources

Table 7 contains unit data for existing and planned generating resources.[16] Cane Run 6 was retired in March 2015, Cane Run 4-5 were retired in June 2015 with the commercial operation of Cane Run 7, and Green River 3-4 were retired in September 2015. No additional retirements are assumed during the planning period.

To comply with environmental regulations, the Companies recently installed fabric filter baghouses ("baghouses") on Brown 3, Ghent 1-4, Mill Creek 1, Mill Creek 2, Mill Creek 4, and Trimble County 1. New flue gas desulfurization systems ("FGDs") were also installed on Mill Creek 1, Mill Creek 2, and Mill Creek 4. A baghouse and new FGD will be installed on Mill Creek 3 by June 2016. No additional changes to emission controls, operating characteristics, unit ratings, unit availabilities, or fuel supply are assumed for existing units over the planning period.

[16] Note that the net capability 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.

## Table 7 – Existing and Future Generating Resources

| Plant Name | Unit No. | Location | Status | Operation Date | Facility Type | Net Capability (MW) | | Entitlement | | Fuel Type | Unit Type | Scheduled Upgrades and Retirements |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | 2015/16 Winter | 2015 Summer | KU | LGE | | | |
| Cane Run | 7 | Louisville, KY | Existing | 2015 | Turbine | 673 | 642 | 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 | | 414 | 410 | | | | | 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 | | | | | |
| Ghent | 1 | Ghent, KY | Existing | 1974 | Steam | 476 | 474 | 100% | | Coal (Barge) | Baseload | None |
| | 2 | | | 1977 | | 477 | 495 | | | | | 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 | | | | | Baghouse, FGD 2016 |
| | 4 | | | 1982 | | 486 | 477 | | | | | None |
| Ohio Falls | 1-8 | Louisville, KY | Existing | 1928 | Hydro | Run of River (37/58) | | | 100% | Water | Hydro | 10 MW upgrade 2014-2017 |
| OVEC | N/A | Gallipolis, OH<br>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 | 511 (383) | 511 (383) | 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 | | | | | | | | | | | | |
| E.W. Brown Solar | 1 | Burgin, KY | Proposed | 2016 | Solar | 0 | 8 | 61% | 39% | Solar | Solar PV | None |
| 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.[17]

## 3.1 Economic Outlook

Economic growth remains on a slow but steady upward trajectory in the LG&E/KU service territory. According to the U.S. Bureau of Economic Analysis, Kentucky's real gross state product increased by only 1.0 percent last year, well below the 2.4 percent growth rate in the U.S. However, IHS Global Insight is forecasting growth of 2.5 percent for 2015-2020 for Kentucky, much closer to the expected U.S. economic growth rate of 2.8 percent.

One major reason for the healthier outlook is the exceptional pace of job growth in the Commonwealth over the past 18 months. Kentucky added an average of 3,158 jobs per month in 2015, the strongest pace of growth since 1999. In 2016, job growth is forecast to slip to 1,550 per month (January-July), but it is still above the long-term trend and Kentucky's unemployment rate has dropped below the national average. But the apparent improvement in Kentucky's unemployment rate is not as impressive as it first appears: Kentucky's labor-force participation rate has materially declined over the same period.

The increase in job growth and subsequent boost to real consumer spending should lead to growth in other sectors as well, such as residential construction and commercial activity. While the state's urban areas, particularly Louisville and Lexington, have seen population growth, the rural regions of Kentucky continue to suffer hardships. Residential population growth of 0.5 percent per year in the LG&E service territory and 0.4 percent per year for the combined KU and Old Dominion Power Company ("ODP") service territory through 2020, are below the previous year's forecast (0.7 percent and 0.6 percent, respectively) due to a slower pace of population growth in Kentucky according to IHS Global Insight.

Commercial business growth is expected to continue in the state's urban centers. However, stagnant to declining growth rates in the rural regions of the state, particularly areas which have been hit hard by the loss of industries and/or population flight, continue to temper the increase in total commercial customers in the Companies' service territory. Overall, the forecast for commercial customer growth is slightly higher than the prior forecast.

Kentucky's manufacturing sector continues to show signs of strength, with foreign exports contributing 14.5 percent of the Commonwealth's GSP, up from 13.6 percent last year. Auto makers are benefiting from a significant period of expansion, with national sales this year on pace to be the strongest since 2000. However, there is a risk to this sector from a potential slowdown in automobile sales in the years ahead as the U.S. market becomes saturated with new vehicles.

Job losses in the coal mining sector remain a net drag on the economies of Kentucky and southwestern Virginia. Unfortunately, the situation is not likely to reverse itself any time soon. Though many emerging market economies are buying up coal in large quantities for power generation, coal from Central Appalachia is not economically competitive with foreign suppliers or Powder River Basin coal. Meanwhile, many U.S. utilities have shifted to burning more natural gas and less coal in recent years as

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

the former has benefited from a boon in supply from shale formations, cutting costs dramatically, while the latter has suffered from a slew of regulatory constraints.

## 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 is largely due to lackluster gains in 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 forecast. 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 territory.

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, Combined Company load is expected to decline at a pace of 0.4 percent per year, compared 0.1 percent previously, as a result of the loss of many Municipal customers. Excluding these municipal losses, the compound annual growth rate ("CAGR") for the Companies is 0.5 percent compared to 0.8 percent in the previous plan over the next five years. With the loss of the municipal load, combined LG&E, KU, and ODP load is expected to grow at a CAGR of only 0.03 percent from 2016-2030.

Summer peak demand forecasts have been reduced as a result of the lower energy forecast. Summer 2016 is now expected to peak at 6,948 MW, including the effect of Direct Load Control (DLC), compared to 6,998 MW in the prior forecast. From 2016-2030, including the loss of the municipal customers, peak demand is expected to grow at a CAGR of 0.09 percent.

Table 8 through Table 11 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 8 – KU Calendar Actual Sales by Jurisdiction (GWh)**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| Kentucky Retail | 18,527 | 18,889 | 18,280 |
| Kentucky Wholesale | 1,880 | 1,886 | 1,855 |
| Virginia Retail | 862 | 836 | 767 |
| Total System | 21,269 | 21,610 | 20,902 |

**Table 9 – KU Calendar Forecast Sales by Jurisdiction (GWh)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Kentucky Retail | 18,765 | 18,901 | 18,966 | 19,004 | 19,049 | 19,078 | 19,113 | 19,155 | 19,216 | 19,238 | 19,299 | 19,367 | 19,445 | 19,518 | 19,596 |
| Kentucky Wholesale | 1,886 | 1,849 | 1,838 | 900 | 446 | 449 | 453 | 457 | 462 | 466 | 470 | 473 | 473 | 473 | 473 |
| Virginia Retail | 784 | 774 | 764 | 760 | 754 | 750 | 749 | 746 | 746 | 741 | 738 | 734 | 732 | 731 | 728 |
| Total System | 21,434 | 21,525 | 21,567 | 20,664 | 20,248 | 20,277 | 20,315 | 20,358 | 20,423 | 20,445 | 20,506 | 20,575 | 20,650 | 20,722 | 20,798 |

**Table 10 – ODP Calendar Actual Sales by Class (GWh)**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| Residential | 402 | 406 | 373 |
| Commercial | 188 | 189 | 193 |
| Industrial/Mine Power | 191 | 165 | 126 |
| Lighting | 2 | 1 | 2 |
| Public Authority/Municipal Pumping | 80 | 75 | 73 |
| Total System | 862 | 836 | 767 |

**Table 11 – ODP Calendar Forecast Sales by Class (GWh)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 384 | 380 | 373 | 370 | 364 | 360 | 356 | 353 | 352 | 349 | 346 | 344 | 342 | 340 | 338 |
| Schools | 19 | 19 | 18 | 17 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| General Service | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 91 | 91 |
| Large Power | 283 | 278 | 276 | 275 | 276 | 278 | 279 | 280 | 280 | 280 | 278 | 277 | 277 | 277 | 276 |
| 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 | 784 | 774 | 764 | 760 | 754 | 750 | 749 | 746 | 746 | 741 | 738 | 734 | 732 | 731 | 728 |

## 3.3 Resource Summary

The Companies have retired seven coal units since 2013: Tyrone 3 in February 2013, Cane Run 6 in March 2015, Cane Run 4-5 in June 2015, and Green River 3-4 in September 2015. To offset this loss of energy and capacity, Cane Run 7, a 640 MW NGCC facility, was commissioned at the Companies' Cane Run station on June 19, 2015. Nine KU municipal customers provided notices of termination of their wholesale power agreements in April 2014, resulting in a summer peak demand reduction of approximately 325 MW after April 30, 2019.[18] 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 are also constructing a 10 MW photovoltaic ("PV") solar facility at the E. W. Brown station ("Brown Solar") which is expected to be commissioned in May 2016.[19]

Table 12 details the Companies' current capacity supply/demand balance for the 15-year planning period.[20] 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 12, "Planned/Proposed Resources" reflects the addition of the Brown Solar facility, which is expected to be commissioned in May 2016. The Bluegrass Agreement (165 MW) is included in "Firm Purchases" along with the Companies' share of OVEC (152 MW). With the planned changes to the Companies' generation portfolio and with 480 MW of demand reduction from DSM programs and 136 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning in 2029.

[18] The wholesale power contract with the City of Paris provided for a 3-year termination notice so their contract will terminate on April 30, 2017. The summer peak load of the City of Paris is forecasted to be 16 MW.

[19] The KPSC approved the construction of Brown Solar in December 2014.

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

**Table 12 – Resource Summary (MW, Summer)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| Forecast Peak Load | 7,356 | 7,430 | 7,485 | 7,234 | 7,234 | 7,457 | 7,485 | 7,513 |
| DSM | (408) | (442) | (481) | (490) | (480) | (480) | (480) | (480) |
| Net Peak Load | 6,948 | 6,988 | 7,004 | 6,744 | 6,754 | 6,977 | 7,005 | 7,033 |
| | | | | | | | | |
| Existing Resources[21] | 7,815 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 | 7,819 |
| Planned/Proposed Resources[22] | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Firm Purchases[23] | 317 | 317 | 317 | 152 | 152 | 152 | 152 | 152 |
| Curtailable Load | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| Total Supply | 8,276 | 8,280 | 8,280 | 8,115 | 8,115 | 8,115 | 8,115 | 8,115 |
| | | | | | | | | |
| Reserve Margin ("RM") | 19.1% | 18.5% | 18.2% | 20.3% | 20.1% | 16.3% | 15.8% | 15.4% |
| | | | | | | | | |
| RM Shortfall (16% RM)* | 216 | 174 | 155 | 292 | 280 | 21 | (11) | (43) |

*Negative values reflect reserve margin shortfalls.

While meeting customers' peak demand is critical, it is also vital to reliably serve their energy needs all year round at the lowest reasonable cost. As seen in Table 12, energy requirements are forecast to grow by 0.1 TWh over the next 15 years after reductions for DSM and the municipal contract termination.[24] This translates into a compound annual growth rate of 0.03 percent.

**Table 13 – Energy Requirements (TWh, After DSM)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| Energy Requirements | 35.4 | 35.6 | 35.7 | 34.8 | 34.4 | 35.3 | 35.4 | 35.6 |

The energy requirements in Table 13 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.[25] In the proceedings of that case, this forecast was deemed reasonable.[26]

[21] Existing resources include the retirement of Tyrone 3 in February 2013, Cane Run 6 in March 2015, Cane Run 4-5 in June 2015, and Green River 3-4 in September 2015, as well as the addition of Cane Run 7 in June 2015.
[22] Planned/Proposed Resources include Brown Solar in May 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.
[25] Please see CASE NO. PUE-2016-00017 - DIRECT TESTIMONY OF CHARLES R. SCHRAM, DIRECTOR - ENERGY PLANNING, ANALYSIS, AND FORECASTING, LG&E AND KU SERVICES COMPANY at pages 3-6 and Exhibit CRS-1 for a complete description of the load forecast methods, models, and assumptions used to prepare the load forecasts.
[26] Please see PRE-FILED TESTIMONY OF DIANE W. JENKINS, KENTUCKY UTILITIES COMPANY, D/B/A OLD DOMINION POWER COMPANY, CASE NO. PUE-2016-00017 at pages 6-9.

# 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 that will be modeled in the more detailed expansion planning analysis.

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 to be used in the expansion planning analysis.

## 4.2 Generation Technology Options

### 4.2.1 Technology Options Summary

The list of generation technology options evaluated in the 2016 IRP was unchanged from the 2015 IRP. With the exception of the advanced battery energy storage technology, 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 from [SOURCE] for a subset of the technologies considered and only the cost of the advanced battery energy storage technology was materially different. Table 14 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. The list of generation technology types includes natural gas, coal-fired, waste to energy, energy storage, renewable, and nuclear technologies. Each of these technology types is discussed in more detail in the following sections.

**Table 14 – 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_– Twelve 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 |

| Technology Type | Generation Technology Option | Representative Technology Option |
|---|---|---|
| Natural Gas | 1x1 NGCC F-Class – 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 |
| 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 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 | MSW Stoker Fired | MSW Stoker Fired |
| Waste to Energy | RDF Stoker Fired | RDF Stoker Fired |
| Waste to Energy | Wood Stoker Fired | Wood Stoker Fired |
| Waste to Energy | Landfill Gas 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 | 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. However, energy storage technology options are still not cost effective. In addition, land use requirements for pumped hydroelectric facilities make this storage technology option not very suitable in the Companies' territory.

#### 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 base-load 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 11 percent of the total wind capacity. The assumed annual capacity factor of wind is 27 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.[27]

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.

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[27] 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.

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 80 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.

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

#### 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 15 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 15 – 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] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LM6000 – Four Units | Gas | 195 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LMS100 – One Unit | Gas | 106 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LMS100 – Two Units | Gas | 211 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7EA – One Unit | Gas | 87 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7EA – Three Units | Gas | 260 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7F-5 – One Unit | Gas | 211 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7F-5 – Three Units | Gas | 634 | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW – Six Units | Gas | 100 | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 200 MW – Twelve Units | Gas | 200 | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 1 MW – Five Units | Gas | 1 | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 3 MW – Fifteen Units | Gas | 3 | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW – Four Units | Gas | 11 | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 30 MW – Twelve Units | Gas | 34 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 GE 7F-5 | Gas | 315 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 GE 7F-5 - Fired | Gas | 357 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 MHI GAC | Gas | 397 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 MHI GAC - Fired | Gas | 452 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 MHI JAC | Gas | 441 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 1x1 MHI JAC - Fired | Gas | 503 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 2x1 GE 7F-5 | Gas | 638 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined-cycle 2x1 GE 7F-5 - Fired | Gas | 719 | [redacted] | [redacted] | [redacted] | [redacted] |

| 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 2x1 MHI GAC | Gas | 796 | [redacted] | | | |
| Combined-cycle 2x1 MHI GAC - Fired | Gas | 901 | [redacted] | | | |
| Combined-cycle 2x1 MHI JAC | Gas | 884 | [redacted] | | | |
| Combined-cycle 2x1 MHI JAC - Fired | Gas | 1,003 | [redacted] | | | |
| Combined-cycle 3x1 GE 7F-5 | Gas | 960 | [redacted] | | | |
| Combined-cycle 3x1 GE 7F-5 - Fired | Gas | 1,082 | [redacted] | | | |
| Combined-cycle 3x1 MHI GAC | Gas | 1,199 | [redacted] | | | |
| Combined-cycle 3x1 MHI GAC - Fired | Gas | 1,356 | [redacted] | | | |
| Combined-cycle 3x1 MHI JAC | Gas | 1,330 | [redacted] | | | |
| Combined-cycle 3x1 MHI JAC - Fired | Gas | 1,509 | [redacted] | | | |
| Subcritical Pulverized Coal | Coal | 500 | [redacted] | | | |
| Subcritical Pulverized Coal with CC | Coal | 425 | [redacted] | | | |
| Circulating Fluidized Bed | Coal | 500 | [redacted] | | | |
| Circulating Fluidized Bed with CC | Coal | 425 | [redacted] | | | |
| Supercritical Pulverized Coal | Coal | 500 | [redacted] | | | |
| Supercritical Pulverized Coal with CC | Coal | 425 | [redacted] | | | |
| Supercritical Pulverized Coal | Coal | 750 | [redacted] | | | |
| Supercritical Pulverized Coal with CC | Coal | 638 | [redacted] | | | |
| 2x1 Integrated Gasification | Coal | 618 | [redacted] | | | |
| 2x1 Integrated Gasification with CC | Coal | 482 | [redacted] | | | |
| MSW Stoker Fired | MSW | 50 | [redacted] | | | |
| RDF Stoker Fired | RDF | 50 | [redacted] | | | |
| Wood Stoker Fired | Biomass | 50 | [redacted] | | | |
| Landfill Gas IC Engine | LFG | 5 | [redacted] | | | |
| Anaerobic Digester Gas IC Engine | Sewage | 5 | [redacted] | | | |
| Co-fired Circulating Fluidized Bed | Coal/Biomass | 50 | [redacted] | | | |
| Co-fired Circulating Fluidized Bed | Coal/TDF | 50 | [redacted] | | | |
| Pumped Hydro Energy Storage | Charging | 200 | [redacted] | | | |
| Adv. Battery Energy Storage | Charging | 10 | [redacted] | | | |
| Compressed Air Energy Storage | Gas/Charging | 135 | [redacted] | | | |
| Wind | No Fuel | 50 | [redacted] | | | |
| Solar Photovoltaic | No Fuel | 50 | [redacted] | | | |
| Solar Thermal | No Fuel | 50 | [redacted] | | | |
| Hydro Electric | No Fuel | 50 | [redacted] | | | |
| Small Modular Nuclear | U235 | 225 | [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 59ºF 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 lbs/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

Because of the uncertainty regarding the Investment Tax Credit, renewable technology options were evaluated with and without a 10% ITC.

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.[28] The Companies assumed prices of $26 per solar REC and $11 per wind REC in the supply-side screening analysis.

#### 4.2.3.2 Financial Inputs

Table 16 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.

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

**Table 16 – 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 | 6.51% |

#### 4.2.3.3 Fixed Charge Rates, Book Life and Tax Life Assumptions

Table 17 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.

**Table 17 – FCR, Book Life and Tax Life**

| Technology Types | FCR (%) | Book Life (years) | Tax Life (Years) |
|---|---|---|---|
| Coal | 8.16 | 50 | 20 |
| SCCT | 9.24 | 30 | 15 |
| NGCC | 9.47 | 40 | 20 |
| Wind and Solar | 8.06 | 20 | 5 |
| Hydro | 9.37 | 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 18 are based on market quotes published by Amerex.

Table 18 – $SO_2$ and $NO_X$ Emission Prices ($/short ton)

| Year | Annual NOx | Ozone NOx | $SO_2$ |
|---|---|---|---|
| 2016 | 125.00 | 125.00 | 75.00 |
| 2017 | 125.00 | 132.81 | 100.00 |
| 2018 | 109.38 | 118.06 | 87.50 |
| 2019 | 93.75 | 103.30 | 75.00 |
| 2020 | 78.13 | 88.54 | 62.50 |
| 2021 | 150.00 | 73.78 | 75.00 |
| 2022 | 70.00 | 57.18 | 37.50 |
| 2023 | 46.67 | 141.67 | 25.00 |
| 2024 | 35.00 | 71.67 | 18.75 |
| 2025 | 28.00 | 16.67 | 15.00 |
| 2026 | 10.00 | 11.67 | 12.50 |
| 2027 | 5.00 | 1.67 | 5.00 |
| 2028 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.00 | 0.00 | 0.00 |
| 2035 | 0.00 | 0.00 | 0.00 |
| 2036 | 0.00 | 0.00 | 0.00 |
| 2037 | 0.00 | 0.00 | 0.00 |
| 2038 | 0.00 | 0.00 | 0.00 |
| 2039 | 0.00 | 0.00 | 0.00 |
| 2040 | 0.00 | 0.00 | 0.00 |
| 2041 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.00 | 0.00 |

#### 4.2.3.5 Firm Gas Transportation

Firm gas transportation costs for SCCT and NGCC technology options are listed in Table 19. 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 19 – 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 20 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 20– 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 21. The Mid natural gas price forecast is based on market prices for the short term and the Energy Information Administration's ("EIA") 2015 Annual Energy Outlook ("AEO") for the long term. Prices in 2016-2017 were taken from the Companies' 2016 Business Plan and reflect NYMEX HH monthly forward prices as of 6/18/2015. Prices in 2018-2020 reflect a blend of market prices and a midpoint average curve between the annual HH prices from two EIA AEO 2015 scenarios: "High Oil Price" (a proxy for high gas price) and "High Oil and Gas Resource" (a proxy for low gas price). Blending is 75% market in 2018, 50% market in 2019, and 25% market in 2020. Prices in 2021-2037 reflect the midpoint average curve between the annual HH prices from the "High Oil Price" and "High Oil-Gas Resource" scenarios ("Midpoint"). Prices in 2038-2045 are escalated annually at the 2027-2037 compound annual growth rate of the Midpoint forecast (4.4%) from the 2037 Midpoint forecast prices. Monthly prices after 2017 are calculated using average monthly shape indices derived from the market forwards for 2016-2020. The Low natural gas price forecast is based on EIA's 2015 AEO "High Oil and Gas Resource" scenario. To maintain a consistent spread between the Low and Mid natural gas price scenarios, years 2016-2018 in the Low scenario were adjusted to reflect the 2019 percentage difference between the Low and Mid scenarios. The High natural gas price forecast is based on EIA's 2015 AEO "High Oil Price" scenario.

The forecast mine-mouth coal prices for the Companies' open coal position for Illinois Basin high-sulfur ("ILB-HS") and Powder River basin ("PRB") coal were used to develop the delivered coal prices used in the analysis. The coal prices in Table 21 are based on a 75% blend of ILB-HS coal and 25% PRB coal. Through 2020, these coal prices are based on (i) market bid prices and (ii) a forecast developed by Wood Mackenzie (an energy and mining research and consulting firm) in the spring of 2015.[29] In 2020-2040, these prices were escalated at the annual growth rates in the average coal price forecast from EIA's AEO 2015 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 2016 and 2017 are based fully on the bid price curve. Prices in 2018 are 75% bid prices, 25% Wood Mackenzie. Prices in 2019 and 2020 are blended 50% bid/50% Wood Mackenzie and 25% bid/75% Wood Mackenzie, respectively.

**Table 21 – Natural Gas and Coal Prices (Nominal $/mmBtu)**

| Year | Delivered Natural Gas Prices – Low | Delivered Natural Gas Prices – Mid | Delivered Natural Gas Prices – High | Coal Prices Blended ( 75% ILB-HS, 25% PRB) |
|---|---|---|---|---|
| 2016 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2017 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2018 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2019 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2020 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2021 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2022 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2023 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2024 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2025 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2026 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2027 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2028 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2029 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2030 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2031 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2032 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2033 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2034 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2035 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2036 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2037 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2038 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2039 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2040 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2041 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2042 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2043 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2044 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2045 | [redacted] | [redacted] | [redacted] | [redacted] |

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 Electric Power Research Institute ("EPRI") and Burns & McDonnell. Table 22 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 22 – Non-Conventional Fuels (2013 Nominal $/mmBtu)**

| | Non-Conventional Delivered Fuel Prices Source (EPRI) | | |
|---|---|---|---|
| **Fuel Type** | **Low** | **Mid** | **High** |
| Municipal Solid Waste | [redacted] | | |
| Refuse Derived Fuel | | | |
| Biomass | | | |
| Landfill Gas | | | |
| Sewage | | | |
| Tire Derived Fuel | | | |
| Uranium (U235) | | | |

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 U-235

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 23 lists the charging costs used in the analysis.

**Table 23 – Charging Cost ($/MWh)**

| Year | Charging Cost ($/MWh) | | |
|---|---|---|---|
| | Low | Mid | High |
| 2016 | [redacted] | | |
| 2017 | | | |
| 2018 | | | |
| 2019 | | | |
| 2020 | | | |
| 2021 | | | |
| 2022 | | | |
| 2023 | | | |
| 2024 | | | |
| 2025 | | | |
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| 2027 | | | |
| 2028 | | | |
| 2029 | | | |
| 2030 | | | |
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| 2038 | | | |
| 2039 | | | |
| 2040 | | | |
| 2041 | | | |
| 2042 | | | |
| 2043 | | | |
| 2044 | | | |
| 2045 | | | |

### 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] Technology options that were ranked among the top four least-cost technology options in any case were considered for the more detailed expansion planning analysis.

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 27% and 20%, respectively. The hydroelectric option was limited to a 40% 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 especially in Kentucky.[31]
- 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.

Given the uncertainty in REC prices and the availability of ITCs for renewable technologies, two iterations of cases each were evaluated:

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10% ITC and RECs: This iteration incorporated a 10% ITC and REC market prices for solar and wind technologies.

## 4.5 Supply-Side Screening Results

Table 24 lists the technology options that were ranked among the top four least-cost technology options in the "No ITC or RECs" iteration for at least one of the 270 cases. Table 25 contains the same information for the "10% ITC and RECs" iteration. A comparison of levelized costs for each technology is included in Section 6 – Appendix A.

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

[31] Since 1984, the Kentucky General Assembly has had a moratorium on any nuclear plant construction without a plan for permanent waste disposal.

**Table 24 – 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 | 212 | 5 | 21 | 32 | **270** |
| 2x1 NGCC G/H-Class – DF | 0 | 86 | 184 | 0 | **270** |
| 2x1 NGCC F-Class | 0 | 149 | 51 | 17 | **217** |
| 2x1 NGCC F-Class – DF | 0 | 0 | 0 | 155 | **155** |
| SCCT F-Class – Three Units | 58 | 2 | 10 | 7 | **77** |
| SCCT F-Class – One Unit | 0 | 28 | 4 | 21 | **53** |
| 1x1 NGCC G/H-Class | 0 | 0 | 0 | 38 | **38** |

**Table 25 – Frequency of Occurrence of the Generation Technology Option in the Top Four with ITC & Wind and Solar RECs**

| Generation Technology Option | # Occurrences 1st | 2nd | 3rd | 4th | Total |
|---|---|---|---|---|---|
| 2x1 NGCC G/H-Class - DF | 0 | 65 | 195 | 10 | **270** |
| 2x1 NGCC G/H-Class | 205 | 15 | 22 | 19 | **261** |
| 2x1 NGCC F-Class | 0 | 156 | 37 | 18 | **211** |
| 2x1 NGCC F-Class - DF | 0 | 0 | 0 | 133 | **133** |
| SCCT F-Class – Three Units | 55 | 1 | 8 | 3 | **67** |
| 1x1 NGCC G/H-Class | 0 | 0 | 2 | 54 | **56** |
| SCCT F-Class – One Unit | 0 | 27 | 1 | 21 | **49** |
| Wind | 1 | 6 | 4 | 2 | **13** |
| Solar Photovoltaic | 9 | 0 | 1 | 1 | **11** |
| Compressed Air Energy Storage | 0 | 0 | 0 | 9 | **9** |

The results in both tables are very similar with natural gas technology options dominating as least-cost options. In both iterations, the "2x1 NGCC G/H-Class" option was least cost in more than 200 of the 270 cases. The "SCCT F-Class – Three Units" option was least-cost in over 50 cases in both iterations. In the "10% ITC and RECs" iteration, the solar PV and wind technology options were ranked among the top four least-cost technology options in multiple cases.

In this analysis, changes in non-conventional fuels are positively correlated with changes in natural gas. When changes in non-conventional fuels are assumed to be negatively correlated with natural gas, the results of the analysis are unchanged.

Table 26 lists the generation technology options that were evaluated in the detailed expansion planning analysis. The two F-Class NGCC options, the 2x1 NGCC G/H-Class option with duct firing ("DF"), and the hydroelectric options in Table 24 and Table 25 were ultimately excluded from the detailed analysis. Proposed GHG regulation and uncertainty in gas prices make the added efficiency of the G-Class option more cost-effective than the F-Class option. Additionally, the capital and fixed costs for the G-Class option are lower on a per-kilowatt ("kW") basis. The 2x1 NGCC G/H-Class option with duct firing was consistently less favorable than the 2x1 NGCC G/H-Class option without duct firing.[32] The CAES options were eliminated because they ranked among the top four least-cost options in only ten or fewer of 270 cases. In addition, the Companies are not aware of any viable sites for new CAES capacity near their service territories.

[32] In addition, the 2x1 options with duct firing are not materially different from the 2x1 options without duct firing. Duct firing serves as a means to adjust the size and flexibility of a NGCC unit.

**Table 26 – List of Generation Technology Options for the Expansion Plan Analysis**

| Generation Technology Options |
|---|
| 2x1 NGCC G/H-Class |
| 1x1 NGCC G/H-Class |
| SCCT F-Class – Three Units |
| SCCT F-Class – One Unit |
| Solar Photovoltaic |
| Wind |

The list of generation technology options in Table 26 is identical to the list of technology options that passed the screening analysis for the 2015 IRP.

# 5 Expansion Planning Analysis

## 5.1 Key Inputs and Uncertainties

The Companies evaluate long-term resource decisions under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy) and natural gas prices are the most important to consider when evaluating long-term generating resources. Therefore, the Companies considered these uncertainties in this analysis to understand their impact on the Companies' optimal expansion plan.

### 5.1.1 Load Forecast

The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost. Therefore, the forecast of future demand and energy has a significant impact on the Companies' optimal expansion plan. The volume of future load (demand and energy) is driven by future economic activity, the adoption rate of new and existing DSM programs, and the development of new electric end-uses (e.g., electric vehicles). The Companies utilized the best information available to develop a reasonable long-term "Base" load forecast. As with any long-term forecast, the uncertainty associated with it tends to grow through time. Therefore, "High" and "Low" load forecasts were also developed, which reflect the statistical uncertainty about the Base load forecast. Table 27 lists the three load forecast scenarios evaluated in this analysis.

**Table 27 – Native Load Scenarios**

| | Energy Requirements (GWh) | | | Peak Demand (MW) | | |
|---|---|---|---|---|---|---|
| Year | Low | Base | High | Low | Base | High |
| 2016 | 33,729 | 35,434 | 37,139 | 6,619 | 6,948 | 7,277 |
| 2017 | 33,852 | 35,580 | 37,309 | 6,655 | 6,988 | 7,321 |
| 2018 | 33,916 | 35,670 | 37,424 | 6,667 | 7,004 | 7,342 |
| 2019 | 32,989 | 34,767 | 36,545 | 6,408 | 6,744 | 7,080 |
| 2020 | 32,638 | 34,388 | 36,137 | 6,419 | 6,754 | 7,090 |
| 2021 | 32,719 | 34,464 | 36,209 | 6,450 | 6,786 | 7,122 |
| 2022 | 32,818 | 34,559 | 36,299 | 6,484 | 6,820 | 7,156 |
| 2023 | 32,928 | 34,664 | 36,400 | 6,516 | 6,852 | 7,189 |
| 2024 | 33,068 | 34,799 | 36,530 | 6,538 | 6,874 | 7,209 |
| 2025 | 33,139 | 34,867 | 36,595 | 6,555 | 6,891 | 7,227 |
| 2026 | 33,265 | 34,992 | 36,718 | 6,581 | 6,918 | 7,254 |
| 2027 | 33,393 | 35,119 | 36,846 | 6,609 | 6,946 | 7,283 |
| 2028 | 33,548 | 35,277 | 37,006 | 6,638 | 6,977 | 7,315 |
| 2029 | 33,682 | 35,416 | 37,151 | 6,665 | 7,005 | 7,345 |
| 2030 | 33,820 | 35,563 | 37,306 | 6,690 | 7,033 | 7,376 |

Energy and peak demand grow at similar rates in each of the three load scenarios. The Low load scenario reflects an environment where a significant portion of the Companies' load is lost. Compared to the Base load scenario, peak demand in the Low load scenario is approximately 300 MWs lower in 2016. The High load scenario reflects an environment where a significant amount of load is gained. Compared to the Base load scenario, peak demand in the High load scenario is approximately 300 MWs higher in 2016.

### 5.1.2 Natural Gas Prices

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 expansion planning analysis considered three natural gas price scenarios. The "Low," "Mid," and "High" scenarios are listed in Section 4.3.3.1 in Table 21.

### 5.1.3 Summary of Scenarios

The native load and natural gas price scenarios were combined to produce nine scenarios for the expansion planning analysis, listed in Table 28.

**Table 28 – Analysis Scenarios**

| Scenario | Native Load | Gas Price |
|---|---|---|
| 1 | Low | Low |
| 2 | Low | Mid |
| 3 | Low | High |
| 4 | Base | Low |
| 5 | Base | Mid |
| 6 | Base | High |
| 7 | High | Low |
| 8 | High | Mid |
| 9 | High | High |

### 5.1.4 Other Inputs

#### 5.1.4.1 GHG Regulations

When more information is known regarding the costs and implementation of the CPP, the Companies will conduct a detailed study to determine the most cost-effective compliance plan. Given the extended compliance deadlines, this resource assessment assumes – in the absence of better information – that CPP compliance costs will not result in any changes to the Companies' generating portfolio.

#### 5.1.4.2 Supply-Side Screening Analysis Results

Table 29 lists the capital costs and unit characteristics for each of the supply-side options that passed the Supply-Side Screening Analysis. Capital costs for these options were developed by Burns & McDonnell. A summary of Burns & McDonnell's Generation Technology Study is included in Section 4.2.2 in Table 15. The complete report is also included in Volume III, Technical Appendix.

**Table 29 – Cost and Unit Characteristics for Generation Technology Options (2013 $)**

| Unit Type | 2x1 NGCC | 1x1 NGCC | Simple-Cycle CT | 3 Simple-Cycle CTs | Wind Turbines | Solar PV |
|---|---|---|---|---|---|---|
| Reference Name[33] | 2x1G | 1x1G | SCCT | CTx3 | Wind | SLPV |
| Net Capability (MW) | | | | | | |
| Summer | 737 | 368 | 201 | 602 | 50 | 50 |
| Winter | 859 | 429 | 220 | 659 | 50 | 50 |
| Overnight Installed Cost ($/kW)[34] | [redacted] | | | | | |
| Total Non-Fuel Variable O&M ($/MWh)[35] | [redacted] | | | | | |
| Total Fixed O&M ($/kW-yr)[36] | [redacted] | | | | | |
| Full Load Heat Rate (mmBtu/MWh) | [redacted] | | | | | |
| Unavailability (%)[37] | [redacted] | | | | | |

NGCC technology has higher capital costs and fixed O&M, but much better heat rates than simple-cycle CTs. The 3 SCCTs option takes advantage of economies of scale, which results in very low capital costs. Wind and Solar options have much higher capital costs than other options, but no energy costs.

#### 5.1.4.3 Reserve Margin

The Companies target a minimum 16 percent reserve margin for the purpose of developing expansion plans. The derivation of this reserve margin target is discussed in detail in the report titled *2014 Reserve Margin Study* located in Volume III, Technical Appendix of the 2014 IRP.

#### 5.1.4.4 Existing Unit Characteristics

Table 30 lists the summer capacity rating, equivalent unplanned outage rate ("EUOR"), and average full load heat rate for each of the Companies' existing units. EUOR is approximately the sum of each unit's equivalent forced outage rate and maintenance outage rate.

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[33] Reference names are used to more easily compare expansion plans.
[34] Installed cost is based on annual average capacity.
[35] Variable O&M for NGCC and SCCT options includes long-term service agreement costs.
[36] Fixed O&M for NGCC and SCCT options includes costs associated with reserving firm gas-line capacity.
[37] Unavailability for NGCC and SCCT options is the long-term steady-state outage rate expected after initial operation. For wind and solar options, unavailability reflects the expected capacity factor (Unavailability = 1 – Capacity Factor).
[38] Wind turbine capacity factor modeled at 27% with 11% of the capacity counting toward reserve margin.
[39] Solar photovoltaic capacity factor modeled at 17.4% with 80% of the capacity counting toward reserve margin.

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Table 30 – Existing Unit Characteristics

| Unit | Installed Year | Net Summer Rating (MW)[40] | EUOR (%) | Average Full Load Heat Rate (mmBtu/MWh) |
|---|---|---|---|---|
| Brown 1 | 1957 | 106 | 8.8% | 10.377 |
| Brown 2 | 1963 | 166 | 8.8% | 10.289 |
| Brown 3 | 1971 | 410 | 7.9% | 10.845 |
| Brown 5 | 2001 | 130 | 18.5% | 12.111 |
| Brown 6 | 1999 | 146 | 6.8% | 10.726 |
| Brown 7 | 1999 | 146 | 6.8% | 10.726 |
| Brown 8 | 1995 | 121 | 7.8% | 12.319 |
| Brown 9 | 1994 | 121 | 7.8% | 12.268 |
| Brown 10 | 1995 | 121 | 7.8% | 12.268 |
| Brown 11 | 1996 | 121 | 7.8% | 12.319 |
| Brown Solar | 2016 | 8 | N/A | N/A |
| Cane Run 7 | 2015 | 642 | 5.0% | 6.842 |
| Cane Run 11 | 1968 | 14 | 50.0% | 16.117 |
| Dix Dam 1-3 | 1925 | 31.5 | N/A | N/A |
| Ghent 1 | 1974 | 474 | 7.9% | 10.843 |
| Ghent 2 | 1977 | 495 | 7.9% | 10.610 |
| Ghent 3 | 1981 | 485 | 7.9% | 11.065 |
| Ghent 4 | 1984 | 465 | 7.9% | 10.955 |
| Haefling 1-2 | 1970 | 24 | 50.0% | 18.000 |
| Mill Creek 1 | 1972 | 300 | 7.9% | 10.430 |
| Mill Creek 2 | 1974 | 297 | 7.9% | 10.598 |
| Mill Creek 3 | 1978 | 391 | 7.9% | 10.539 |
| Mill Creek 4 | 1982 | 477 | 7.9% | 10.726 |
| Ohio Falls 1-8 | 1928 | 58 | N/A | N/A |
| Paddy's Run 11 | 1968 | 12 | 50.0% | 15.479 |
| Paddy's Run 12 | 1968 | 23 | 50.0% | 17.005 |
| Paddy's Run 13 | 2001 | 147 | 12.4% | 10.323 |
| Trimble 1 (75%) | 1990 | 383 | 7.0% | 10.602 |
| Trimble 2 (75%) | 2011 | 549 | 9.0% | 9.254 |
| Trimble 5 | 2002 | 159 | 4.6% | 10.668 |
| Trimble 6 | 2002 | 159 | 4.6% | 10.668 |
| Trimble 7 | 2004 | 159 | 4.6% | 10.668 |
| Trimble 8 | 2004 | 159 | 4.6% | 10.668 |
| Trimble 9 | 2004 | 159 | 4.6% | 10.668 |
| Trimble 10 | 2004 | 159 | 4.6% | 10.668 |
| Zorn 1 | 1969 | 14 | 50.0% | 18.676 |

#### 5.1.4.5 Coal Prices

Table 31 lists the delivered coal price forecasts for each of the Companies' existing coal units.

[40] The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand.

**Table 31 – Coal Prices ($/mmBtu)**

| Year | Brown<br>6# $SO_2$ | Ghent<br>6# $SO_2$ | Mill Creek<br>6# $SO_2$ | Trimble High $SO_2$<br>6# $SO_2$ | Trimble PRB<br>0.8# $SO_2$ |
|---|---|---|---|---|---|
| 2016 | [redacted] | | | | |
| 2017 | | | | | |
| 2018 | | | | | |
| 2019 | | | | | |
| 2020 | | | | | |
| 2021 | | | | | |
| 2022 | | | | | |
| 2023 | | | | | |
| 2024 | | | | | |
| 2025 | | | | | |
| 2026 | | | | | |
| 2027 | | | | | |
| 2028 | | | | | |
| 2029 | | | | | |
| 2030 | | | | | |

#### 5.1.4.6 $SO_2$ and $NO_X$ Prices

Table 18 in Section 4.2.3.4 lists $SO_2$ and $NO_X$ price forecasts for the study period.

#### 5.1.4.7 Financial Inputs

Table 32 lists the key financial inputs that were utilized in the expansion planning analysis.

**Table 32 – Key Financial Inputs**

| Input | Value |
|---|---|
| Return on Equity | 10.0% |
| Cost of Debt | 4.21% |
| Capital Structure | |
| Debt | 47% |
| Equity | 53% |
| Tax Rate | 38.9% |
| Revenue Requirement Discount Rate | 6.51% |

#### 5.1.4.8 Transmission System Costs

Due to the time required to estimate transmission interconnection and enhancement costs for specific resources, these costs are not included in the analysis. Prior to committing to a particular resource, the Companies will issue a request for proposals to evaluate the least-cost self-build resource against other market available resources. Transmission interconnection and enhancement costs will be considered in this analysis.

## 5.2 Expansion Planning Analysis

### 5.2.1 Methodology

The Strategist computer model was used to develop optimal expansion plans for each of the scenarios listed in Table 28. Strategist uses the Companies' peak and energy load forecasts and load shapes for multiple years to create typical monthly load shapes for production costing purposes. System dispatch and operation are simulated using a load duration curve production costing technique. Production costs including fuel, incremental O&M, purchase power, and emission costs are calculated based on inputs including generating unit and purchase power characteristics, fuel costs, and unit or fuel specific emissions information. All combinations of potential options are evaluated to produce a list of resource plans, subject to user specified constraints, that satisfy the Companies' minimum reserve margin criterion. The production cost analysis is combined with an analysis of new construction expenditures to suggest an optimal resource plan and sub-optimal resource plans based on minimizing utility cost.

### 5.2.2 Results

Table 33 shows optimal expansion plans for the nine scenarios evaluated. The number in parentheses following each Reference Name indicates how many units were commissioned in that year. All units commissioned after 2018 are assumed to be commissioned in the month of June. The location of each commissioned unit has not been determined.

**Table 33 – Optimal Expansion Plans**

| **Load** | **LL** | **LL** | **LL** | **BL** | **BL** | **BL** | **HL** | **HL** | **HL** |
|---|---|---|---|---|---|---|---|---|---|
| **Gas Price** | **LG** | **MG** | **HG** | **LG** | **MG** | **HG** | **LG** | **MG** | **HG** |
| 2016 | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS |
| 2017 | | | | | | | | | |
| 2018 | | | | | | | | | |
| 2019 | | | | | | | | | |
| 2020 | | | | | | | | | |
| 2021 | | | | | | | 2x1G( 1) | 2x1G( 1) | 2x1G( 1) |
| 2022 | | | | | | | | | |
| 2023 | | | | | | | | | |
| 2024 | | | | | | | | | |
| 2025 | | | | | | | | | |
| 2026 | | | | | | | | | |
| 2027 | | | | | | | | | |
| 2028 | | | | | | | | | |
| 2029 | | | | 2x1G( 1) | 2x1G( 1) | SCCT( 1) | | | |
| 2030 | | | | | | | | | |

Load: Low (LL), Base (BL), High (HL) Gas Price: Low (LG), Mid (MG), High (HG)

The Companies have a long-term need for capacity beginning in 2029 in the Base load scenario and 2021 in the High load scenario.[41] In five of six Base and High load scenarios, this need was met with NGCC capacity; in one scenario, this need was met with SCCT capacity. In the Low load scenario, the Companies do not have a long-term need for capacity in the study period.

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[41] The analysis assumed additional capacity cannot be added prior to 2021. For this reason, additional capacity is needed in 2021 in the High load scenario.

Based on these results, a natural gas unit will likely be included in the Companies' least cost plan to reliably meet load requirements beyond 2018. In all scenarios but one with a capacity need in the study period, NGCC capacity is the first new unit installed.

# 6 Appendix A – Comparison of Levelized Costs from Supply-Side Screening Analysis at Varying Capacity Factors ("CF")[42]

**Table 34 – No ITC or RECs; 0 $CO_2$ Prices**

| 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] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LM6000_Add-on | 195 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LMS100 | 106 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LMS100_Add-on | 211 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7EA | 87 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7EA_Add-on | 260 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7F-5 | 211 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7F-5_Add-on | 634 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW | 100 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW_Add-on | 200 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 1 MWM | 1 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 1 MW_Add-on | 3 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW | 11 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW_Add-on | 34 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 | 315 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 - Fired | 357 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC | 397 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC - Fired | 452 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 GE 7F-5 | 638 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 GE 7F-5 - Fired | 719 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 MHI GAC | 796 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 MHI GAC - Fired | 901 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Subcritical Pulverized Coal - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CirculatingFluidized Bed - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SupercriticalPulverized Coal - 500 MW - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SupercriticalPulverized Coal - 750 MW - w/Carbon Capture | 638 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2x1 IntegratedGasification CC - w/Carbon Capture | 482 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| RDF Stoker Fired | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Wood Stoker Fired | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Landfill GasIC Engine | 5 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Anaerobic Digester Gas IC Engine | 5 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Co-fired Circulating Fluidized Bed _Coal/Biomass (50/50) | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Co-fired Circulating Fluidized Bed _Coal/TDF (90/10) | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Pumped HydroEnergy Storage | 200 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Adv. BatteryEnergy Storage | 10 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CAES | 135 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Wind EnergyConversion | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SolarPhotovoltaic | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SolarThermal | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| HydroElectric | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.37% | 55 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

## Table 35 – 10% ITC and RECs; 0 $CO_2$ Prices

| 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] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LM6000_Add-on | 195 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LMS100 | 106 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE LMS100_Add-on | 211 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7EA | 87 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7EA_Add-on | 260 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7F-5 | 211 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple Cycle GE 7F-5_Add-on | 634 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW | 100 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW_Add-on | 200 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 1 MWM | 1 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 1 MW_Add-on | 3 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW | 11 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW_Add-on | 34 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 | 315 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 - Fired | 357 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC | 397 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC - Fired | 452 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 GE 7F-5 | 638 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 GE 7F-5 - Fired | 719 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 MHI GAC | 796 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 MHI GAC - Fired | 901 | [redacted] | [redacted] | [redacted] | [redacted] | 9.47% | 40 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Subcritical Pulverized Coal - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CirculatingFluidized Bed - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SupercriticalPulverized Coal - 500 MW - w/Carbon Capture | 425 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SupercriticalPulverized Coal - 750 MW - w/Carbon Capture | 638 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2x1 IntegratedGasification CC - w/Carbon Capture | 482 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| RDF Stoker Fired | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Wood Stoker Fired | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Landfill GasIC Engine | 5 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Anaerobic Digester Gas IC Engine | 5 | [redacted] | [redacted] | [redacted] | [redacted] | 9.24% | 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Co-fired Circulating Fluidized Bed _Coal/Biomass (50/50) | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Co-fired Circulating Fluidized Bed _Coal/TDF (90/10) | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.29% | 50 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Pumped HydroEnergy Storage | 200 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Adv. BatteryEnergy Storage | 10 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CAES | 135 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Wind EnergyConversion | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SolarPhotovoltaic | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SolarThermal | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 8.06% | 20 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| HydroElectric | 50 | [redacted] | [redacted] | [redacted] | [redacted] | 9.37% | 55 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

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

# 7 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.

## 7.1 Input Data

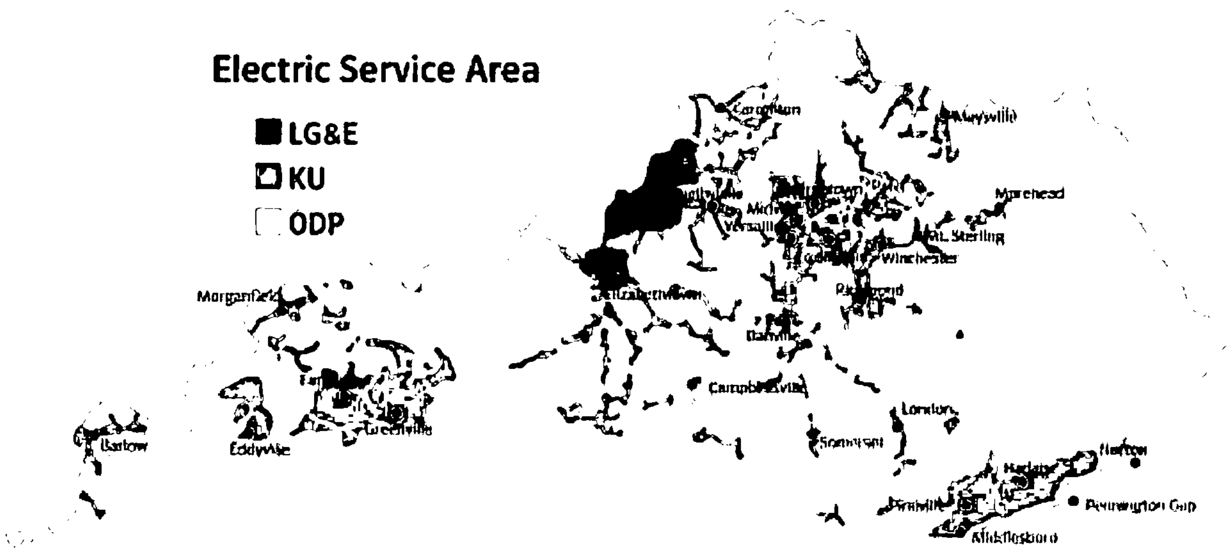
Table 36 provides a summary of data inputs.

**Table 36 – 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.

## 7.2 Forecast Models

The Companies' energy forecast comprises twenty-nine 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.

### 7.2.1 Residential Forecast

The Residential forecast comprises 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.

#### 7.2.1.1 Residential Customer Forecast

The number of residential customers is forecasted by company as a function of the number of forecasted households or forecast 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.

#### 7.2.1.2 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.

$$\text{Use-per-Customer} = a1*XHeat + a2*XCool + a3*XOther$$

The heating, cooling and other components (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.

### 7.2.2 Commercial Forecast

The Commercial forecast comprises ten 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 Large Commercial, ODP General Service, ODP Schools and ODP Municipal Pumping. Each of these rate classes is forecast 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.

#### *7.2.2.1* KU, LG&E, and ODP General Service

The general service forecasts include all customers on the General Service (GS) rate and are comprised of 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 (see description under Residential, 3.1.2).

The customer forecasts are a function of the Residential customer forecasts which incorporate Household and Population growth since, historically, household growth, population growth, and residential customer growth are highly correlated.

#### 7.2.2.2 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 that variables which account for anomalies in the historical data.

#### 7.2.2.3 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.

#### 7.2.2.4 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 forecast 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.

#### 7.2.2.5 LG&E Special Contracts

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

#### 7.2.2.6 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.

#### 7.2.2.7 ODP Municipal Pumping

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

### 7.2.3 Lighting Forecast

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

### 7.2.4 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 forecast customers are removed from the historical energy sales data by rate, while the remaining customers are forecast using econometric models described below. The total rate forecast is the combination of the individually forecast customers and the customers forecast using econometric models.

#### 7.2.4.1 KU Industrial Forecast

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

7.2.4.1.1 Primary

The PS Primary, TOD Primary, and LTOD Primary rates are forecast 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.

7.2.4.1.2 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.

7.2.4.1.3 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.

#### 7.2.4.2 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 forecast separately with specific economic drivers and weather.

7.2.4.2.1 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.

7.2.4.2.2 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.

7.2.4.2.3 Retail Transmission Service

The RTS rate consists of both individually forecast 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.

#### 7.2.4.3 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.

### 7.2.5 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.

### 7.2.6 Billed Demand Forecast

The Billed Demand forecasts are based on historical demand factors, where the demand factor is the billed demand volume divided by the billed sales volume. The historical demand factor is then multiplied by the sales forecast for rates that have billed demand components.

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Exhibit 4

Kentucky Utilities Company and Louisville Gas and Electric Company Sch1

**PEAK LOAD AND ENERGY FORECAST**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| PJM Load Obligation (if appropriate) | | | | | | | | | | | | | | | | | | |
| 1. Utility Peak Load (MW) | | | | | | | | | | | | | | | | | | |
| A. Summer | | | | | | | | | | | | | | | | | | |
| 1. Base Forecast | | | | 7,356 | 7,430 | 7,485 | 7,234 | 7,234 | 7,266 | 7,300 | 7,332 | 7,354 | 7,370 | 7,398 | 7,426 | 7,457 | 7,485 | 7,513 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 207 | 221 | 236 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 |
| 4. Adjusted Load (1) | 6,434 | 6,313 | 6,392 | 6,948 | 6,988 | 7,004 | 6,744 | 6,754 | 6,786 | 6,820 | 6,852 | 6,874 | 6,891 | 6,918 | 6,946 | 6,977 | 7,005 | 7,033 |
| 5. % Increase in Adjusted Load (from previous year) | | -1.9% | 1.2% | 8.7% | 0.6% | 0.2% | -3.7% | 0.2% | 0.5% | 0.5% | 0.5% | 0.3% | 0.2% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| B. Winter (2) | | | | | | | | | | | | | | | | | | |
| 1. Base Forecast | | | | 6,291 | 6,348 | 6,379 | 6,399 | 6,133 | 6,144 | 6,161 | 6,180 | 6,206 | 6,218 | 6,238 | 6,261 | 6,289 | 6,318 | 6,345 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4. Adjusted Load | 5,907 | 7,114 | 7,079 | 6,090 | 6,127 | 6,135 | 6,153 | 5,897 | 5,908 | 5,925 | 5,944 | 5,971 | 5,983 | 6,003 | 6,025 | 6,054 | 6,082 | 6,110 |
| 5. % Increase in Adjusted Load (from previous year) | | 20.4% | -0.5% | -14.0% | 0.6% | 0.1% | 0.3% | -4.2% | 0.2% | 0.3% | 0.3% | 0.4% | 0.2% | 0.3% | 0.4% | 0.5% | 0.5% | 0.4% |
| 2. Energy (GWH) | | | | | | | | | | | | | | | | | | |
| A. Base Forecast | | | | 36,361 | 36,598 | 36,779 | 35,769 | 35,496 | 35,573 | 35,667 | 35,772 | 35,907 | 35,975 | 36,100 | 36,228 | 36,385 | 36,525 | 36,671 |
| B. Conservation, Efficiency | | | | 927 | 1,017 | 1,108 | 1,002 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 |
| C. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D. Adjusted Load | 35,042 | 35,554 | 34,846 | 35,434 | 35,580 | 35,670 | 34,767 | 34,388 | 34,464 | 34,559 | 34,664 | 34,799 | 34,867 | 34,992 | 35,119 | 35,277 | 35,416 | 35,563 |
| E. % Increase in Adjusted Load (from previous year) | | 1.5% | -2.0% | 1.7% | 0.4% | 0.3% | -2.5% | -1.1% | 0.2% | 0.3% | 0.3% | 0.4% | 0.2% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |

**Kentucky Utilities Company and Louisville Gas and Electric Company** Sch1

**PEAK LOAD AND ENERGY FORECAST**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| PJM Load Obligation (if appropriate) | | | | | | | | | | | | | | | | | | |
| 1. Utility Peak Load (MW) | | | | | | | | | | | | | | | | | | |
| A. Summer | | | | | | | | | | | | | | | | | | |
| 1. High Forecast | | | | 7,685 | 7,763 | 7,822 | 7,570 | 7,570 | 7,602 | 7,636 | 7,668 | 7,689 | 7,706 | 7,734 | 7,763 | 7,795 | 7,825 | 7,856 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 207 | 221 | 236 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 |
| 4. Adjusted Load (1) | 6,434 | 6,313 | 6,392 | 7,277 | 7,321 | 7,342 | 7,080 | 7,090 | 7,122 | 7,156 | 7,189 | 7,209 | 7,227 | 7,254 | 7,283 | 7,315 | 7,345 | 7,376 |
| 5. % Increase in Adjusted Load (from previous year) | | -1.9% | 1.2% | 13.8% | 0.6% | 0.3% | -3.6% | 0.1% | 0.4% | 0.5% | 0.5% | 0.3% | 0.2% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| B. Winter (2) | | | | | | | | | | | | | | | | | | |
| 1. High Forecast | | | | 6,593 | 6,655 | 6,691 | 6,727 | 6,445 | 6,454 | 6,470 | 6,487 | 6,512 | 6,523 | 6,542 | 6,563 | 6,591 | 6,620 | 6,647 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4. Adjusted Load | 5,907 | 7,114 | 7,079 | 6,392 | 6,434 | 6,446 | 6,482 | 6,209 | 6,219 | 6,235 | 6,252 | 6,277 | 6,288 | 6,307 | 6,328 | 6,356 | 6,384 | 6,412 |
| 5. % Increase in Adjusted Load (from previous year) | | 20.4% | -0.5% | -9.7% | 0.7% | 0.2% | 0.5% | -4.2% | 0.2% | 0.3% | 0.3% | 0.4% | 0.2% | 0.3% | 0.3% | 0.4% | 0.4% | 0.4% |
| 2. Energy (GWH) | | | | | | | | | | | | | | | | | | |
| A. High Forecast | | | | 38,067 | 38,326 | 38,533 | 37,547 | 37,246 | 37,318 | 37,408 | 37,508 | 37,638 | 37,703 | 37,827 | 37,954 | 38,115 | 38,259 | 38,414 |
| B. Conservation, Efficiency | | | | 927 | 1,017 | 1,108 | 1,002 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 |
| C. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D. Adjusted Load | 35,042 | 35,554 | 34,846 | 37,139 | 37,309 | 37,424 | 36,545 | 36,137 | 36,209 | 36,299 | 36,400 | 36,530 | 36,595 | 36,718 | 36,846 | 37,006 | 37,151 | 37,306 |
| E. % Increase in Adjusted Load (from previous year) | | 1.5% | -2.0% | 6.6% | 0.5% | 0.3% | -2.3% | -1.1% | 0.2% | 0.2% | 0.3% | 0.4% | 0.2% | 0.3% | 0.3% | 0.4% | 0.4% | 0.4% |

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

**PEAK LOAD AND ENERGY FORECAST**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| PJM Load Obligation (if appropriate) | | | | | | | | | | | | | | | | | | |
| 1. Utility Peak Load (MW) | | | | | | | | | | | | | | | | | | |
| A. Summer | | | | | | | | | | | | | | | | | | |
| 1. Low Forecast | | | | 7,027 | 7,097 | 7,147 | 6,898 | 6,898 | 6,930 | 6,963 | 6,996 | 7,018 | 7,035 | 7,061 | 7,088 | 7,118 | 7,145 | 7,170 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 207 | 221 | 236 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 | 244 |
| 4. Adjusted Load (1) | 6,434 | 6,313 | 6,392 | 6,619 | 6,655 | 6,667 | 6,408 | 6,419 | 6,450 | 6,484 | 6,516 | 6,538 | 6,555 | 6,581 | 6,609 | 6,638 | 6,665 | 6,690 |
| 5. % Increase in Adjusted Load (from previous year) | | -1.9% | 1.2% | 3.6% | 0.5% | 0.2% | -3.9% | 0.2% | 0.5% | 0.5% | 0.5% | 0.3% | 0.3% | 0.4% | 0.4% | 0.5% | 0.4% | 0.4% |
| B. Winter (2) | | | | | | | | | | | | | | | | | | |
| 1. Low Forecast | | | | 5,989 | 6,040 | 6,067 | 6,070 | 5,821 | 5,833 | 5,852 | 5,872 | 5,900 | 5,913 | 5,935 | 5,958 | 5,987 | 6,016 | 6,043 |
| 2. Conservation, Efficiency | | | | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| 3. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4. Adjusted Load | 5,907 | 7,114 | 7,079 | 5,788 | 5,819 | 5,823 | 5,825 | 5,585 | 5,597 | 5,616 | 5,636 | 5,664 | 5,678 | 5,699 | 5,723 | 5,752 | 5,780 | 5,807 |
| 5. % Increase in Adjusted Load (from previous year) | | 20.4% | -0.5% | -18.2% | 0.5% | 0.1% | 0.0% | -4.1% | 0.2% | 0.3% | 0.4% | 0.5% | 0.2% | 0.4% | 0.4% | 0.5% | 0.5% | 0.5% |
| 2. Energy (GWH) | | | | | | | | | | | | | | | | | | |
| A. Low Forecast | | | | 34,656 | 34,870 | 35,025 | 33,991 | 33,747 | 33,827 | 33,926 | 34,037 | 34,176 | 34,247 | 34,374 | 34,501 | 34,656 | 34,790 | 34,928 |
| B. Conservation, Efficiency | | | | 927 | 1,017 | 1,108 | 1,002 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 | 1,108 |
| C. Demand-side and Response | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D. Adjusted Load | 35,042 | 35,554 | 34,846 | 33,729 | 33,852 | 33,916 | 32,989 | 32,638 | 32,719 | 32,818 | 32,928 | 33,068 | 33,139 | 33,265 | 33,393 | 33,548 | 33,682 | 33,820 |
| E. % Increase in Adjusted Load (from previous year) | | 1.5% | -2.0% | -3.2% | 0.4% | 0.2% | -2.7% | -1.1% | 0.2% | 0.3% | 0.3% | 0.4% | 0.2% | 0.4% | 0.4% | 0.5% | 0.4% | 0.4% |

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch2

GENERATION

| Scenario: Mid Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 28,015 | 28,490 | 28,459 | 28,871 | 29,984 | 30,746 | 30,737 | 31,863 | 32,055 | 32,211 | 32,081 | 32,609 | 32,503 | 32,628 | 32,812 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 6,657 | 6,297 | 6,393 | 5,081 | 3,588 | 2,903 | 3,006 | 1,986 | 1,927 | 1,840 | 2,114 | 1,693 | 1,955 | 1,974 | 1,937 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 34,989 | 35,136 | 35,226 | 34,326 | 33,946 | 34,023 | 34,118 | 34,223 | 34,356 | 34,425 | 34,549 | 34,676 | 34,832 | 34,977 | 35,123 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 443 | 442 | 442 | 439 | 441 | 439 | 439 | 440 | 441 | 440 | 440 | 440 | 441 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 35,434 | 35,580 | 35,670 | 34,767 | 34,388 | 34,464 | 34,559 | 34,664 | 34,798 | 34,868 | 34,991 | 35,118 | 35,276 | 35,416 | 35,563 |
| 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 |

| Scenario: Mid Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 29,154 | 29,735 | 29,638 | 29,999 | 30,907 | 31,329 | 31,294 | 32,840 | 33,080 | 33,200 | 33,004 | 33,639 | 33,489 | 33,598 | 33,794 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 7,216 | 6,774 | 6,960 | 5,727 | 4,411 | 4,066 | 4,191 | 2,746 | 2,634 | 2,581 | 2,900 | 2,392 | 2,701 | 2,738 | 2,697 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 36,687 | 36,858 | 36,972 | 36,101 | 35,692 | 35,769 | 35,859 | 35,960 | 36,089 | 36,155 | 36,278 | 36,406 | 36,564 | 36,710 | 36,865 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 447 | 447 | 447 | 440 | 441 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 441 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 3 | 3 | 3 | 3 | 3 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 37,137 | 37,307 | 37,422 | 36,544 | 36,136 | 36,209 | 36,299 | 36,400 | 36,530 | 36,595 | 36,718 | 36,846 | 37,006 | 37,151 | 37,306 |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **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 |

| **Scenario: Mid Gas - Low Load** | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 33,560 | 33,002 | 28,938 | 26,755 | 27,121 | 27,176 | 27,634 | 28,985 | 29,732 | 29,739 | 30,716 | 30,912 | 31,084 | 30,984 | 31,439 | 31,384 | 31,513 | 24,778 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 6,215 | 5,942 | 5,925 | 4,541 | 2,838 | 2,173 | 2,265 | 1,398 | 1,341 | 1,241 | 1,467 | 1,140 | 1,348 | 1,355 | 1,326 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 338 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 2,499 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 33,287 | 33,411 | 33,475 | 32,550 | 32,197 | 32,279 | 32,378 | 32,488 | 32,627 | 32,699 | 32,825 | 32,953 | 33,106 | 33,242 | 28,940 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 441 | 440 | 440 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 0 | 0 | 0 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 33,729 | 33,852 | 33,916 | 32,989 | 32,638 | 32,719 | 32,818 | 32,928 | 33,068 | 33,139 | 33,265 | 33,393 | 33,548 | 33,682 | 29,381 |
| **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 |

| **Scenario: High Gas - Base Load** | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 33,560 | 33,002 | 28,938 | 29,060 | 30,024 | 30,878 | 30,929 | 31,641 | 32,098 | 31,996 | 32,434 | 32,324 | 32,402 | 32,203 | 32,698 | 32,601 | 32,684 | 32,822 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 5,612 | 4,763 | 3,974 | 3,023 | 1,931 | 1,551 | 1,748 | 1,415 | 1,658 | 1,649 | 1,972 | 1,604 | 1,857 | 1,917 | 1,925 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 358 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 34,989 | 35,136 | 35,226 | 34,326 | 33,946 | 34,023 | 34,118 | 34,223 | 34,356 | 34,425 | 34,549 | 34,676 | 34,832 | 34,975 | 35,121 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 443 | 442 | 442 | 439 | 441 | 439 | 439 | 440 | 441 | 440 | 440 | 440 | 441 | 440 | 440 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 1 | 2 |
| 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 35,434 | 35,580 | 35,670 | 34,767 | 34,388 | 34,464 | 34,559 | 34,664 | 34,798 | 34,866 | 34,991 | 35,118 | 35,276 | 35,416 | 35,562 |
| **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 |

| Scenario: High Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 30,157 | 31,006 | 31,675 | 31,830 | 32,644 | 33,160 | 32,893 | 33,528 | 33,370 | 33,417 | 33,159 | 33,735 | 33,589 | 33,660 | 33,806 |
| 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 | 0 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 6,213 | 5,502 | 4,923 | 3,896 | 2,673 | 2,235 | 2,493 | 2,058 | 2,345 | 2,364 | 2,745 | 2,296 | 2,601 | 2,676 | 2,685 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 36,687 | 36,858 | 36,972 | 36,101 | 35,692 | 35,769 | 35,859 | 35,960 | 36,089 | 36,155 | 36,278 | 36,408 | 36,564 | 36,710 | 36,865 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 447 | 447 | 447 | 440 | 441 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 441 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 3 | 3 | 3 | 3 | 3 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 37,137 | 37,307 | 37,422 | 36,544 | 36,136 | 36,209 | 36,299 | 36,400 | 36,530 | 36,595 | 36,718 | 36,846 | 37,006 | 37,151 | 37,306 |
| 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 |

| Scenario: High Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 27,859 | 28,969 | 29,998 | 29,922 | 30,497 | 30,886 | 30,837 | 31,186 | 31,128 | 31,227 | 31,096 | 31,506 | 31,460 | 31,556 | 31,687 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 5,111 | 4,094 | 3,104 | 2,253 | 1,326 | 1,019 | 1,167 | 928 | 1,125 | 1,098 | 1,355 | 1,072 | 1,272 | 1,311 | 1,319 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 33,287 | 33,411 | 33,475 | 32,550 | 32,197 | 32,279 | 32,378 | 32,488 | 32,627 | 32,699 | 32.825 | 32.953 | 33,106 | 33,242 | 33.379 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 441 | 440 | 440 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 0 | 0 | 0 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 33,729 | 33,852 | 33,916 | 32,989 | 32,638 | 32,719 | 32,818 | 32,928 | 33,068 | 33,139 | 33,265 | 33,393 | 33,548 | 33,682 | 33,820 |
| 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 |

| Scenario: Low Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 27,194 | 27,603 | 28,185 | 28,079 | 27,764 | 27,694 | 27,633 | 27,892 | 28,202 | 27,993 | 27,773 | 28,259 | 28,854 | 25,890 | 23,481 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 7,477 | 7,183 | 6,667 | 5,874 | 5,808 | 5,955 | 6,111 | 5,956 | 5,780 | 6,058 | 6,402 | 6,043 | 5,604 | 8,713 | 11,269 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 34,988 | 35,135 | 35,226 | 34,326 | 33,946 | 34,023 | 34,118 | 34,223 | 34,356 | 34,425 | 34,549 | 34,676 | 34,832 | 34,977 | 35,123 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 444 | 443 | 442 | 439 | 441 | 439 | 439 | 440 | 441 | 440 | 440 | 440 | 441 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 35,434 | 35,580 | 35,670 | 34,767 | 34,388 | 34,464 | 34,559 | 34,664 | 34,798 | 34,866 | 34,991 | 35,118 | 35,276 | 35,416 | 35,563 |
| 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 |

| Scenario: Low Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 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 | 33,560 | 33,002 | 28,938 | 28,121 | 28,646 | 29,369 | 29,402 | 29,119 | 26,982 | 25,257 | 25,708 | 25,312 | 24,982 | 24,769 | 25,090 | 26,773 | 25,292 | 24,758 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 8,247 | 7,861 | 7,229 | 6,324 | 6,199 | 8,413 | 10,228 | 9,878 | 10,403 | 10,799 | 11,135 | 10,942 | 9,417 | 11,044 | 11,733 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 36,685 | 36,857 | 36,972 | 36,101 | 35,692 | 35,769 | 35,859 | 35,960 | 36,089 | 36,155 | 36,278 | 36,406 | 36,564 | 36,710 | 36,865 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 449 | 447 | 447 | 440 | 441 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 441 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 3 | 3 | 3 | 3 | 3 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 37,137 | 37,307 | 37,422 | 36,544 | 36,136 | 36,209 | 36,299 | 36,400 | 36,530 | 36,595 | 36,718 | 36,846 | 37,006 | 37,151 | 37,306 |
| 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 |

| Scenario: Low Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 33,560 | 33,002 | 28,938 | 26,135 | 26,436 | 26,873 | 26,625 | 26,293 | 26,205 | 26,204 | 26,407 | 26,770 | 26,550 | 26,365 | 26,808 | 27,485 | 27,020 | 26,897 |
| 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 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas | 503 | 1,201 | 2,598 | 6,834 | 6,626 | 6,228 | 5,551 | 5,530 | 5,701 | 5,801 | 5,707 | 5,482 | 5,775 | 6,088 | 5,770 | 5,247 | 5,848 | 6,108 |
| f. Hydro-Conventional | 300 | 344 | 372 | 306 | 334 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 | 359 |
| 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 | 11 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| i. Total Generation (sum of a through h) | 34,363 | 34,552 | 31,910 | 33,287 | 33,411 | 33,475 | 32,550 | 32,197 | 32,279 | 32,378 | 32,488 | 32,627 | 32,699 | 32,825 | 32,953 | 33,106 | 33,242 | 33,379 |
| j. Purchased Power | | | | | | | | | | | | | | | | | | |
| 1. Firm | 854 | 896 | 837 | 442 | 440 | 440 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 | 439 | 440 | 439 | 439 |
| 2. Other | 2,637 | 3,453 | 2,258 | 1 | 1 | 1 | 0 | 0 | 0 | 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) | 503 | 481 | 386 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| m. Total System Firm Energy Requirements | 37,352 | 38,420 | 34,619 | 33,729 | 33,852 | 33,916 | 32,989 | 32,638 | 32,719 | 32,818 | 32,928 | 33,068 | 33,139 | 33,265 | 33,393 | 33,548 | 33,682 | 33,820 |
| **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.)

**Kentucky Utilities Company and Louisville Gas and Electric Company** Sch3

**GENERATION**

| Scenario: Mid Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 80% | 81% | 81% | 84% | 88% | 90% | 90% | 93% | 93% | 94% | 93% | 94% | 93% | 93% | 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 | 1% | 3% | 8% | 19% | 18% | 18% | 15% | 11% | 9% | 9% | 6% | 6% | 5% | 6% | 5% | 6% | 6% | 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: Mid Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 79% | 81% | 80% | 83% | 87% | 88% | 87% | 91% | 92% | 92% | 91% | 92% | 92% | 92% | 92% |
| 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 | 1% | 3% | 8% | 20% | 18% | 19% | 16% | 12% | 11% | 12% | 8% | 7% | 7% | 8% | 7% | 7% | 7% | 7% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: Mid Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *2013* | *2014* | *2015* | *2016* | *2017* | *2018* | *2019* | *2020* | *2021* | *2022* | *2023* | *2024* | *2025* | *2026* | *2027* | *2028* | *2029* | *2030* |
| **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 | 98% | 96% | 91% | 80% | 81% | 81% | 85% | 90% | 92% | 92% | 95% | 95% | 95% | 94% | 95% | 95% | 95% | 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 | 1% | 3% | 8% | 19% | 18% | 18% | 14% | 9% | 7% | 7% | 4% | 4% | 4% | 4% | 3% | 4% | 4% | 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% | 9% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: High Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 83% | 85% | 88% | 90% | 93% | 94% | 94% | 95% | 94% | 94% | 93% | 94% | 94% | 93% | 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 | 1% | 3% | 8% | 16% | 14% | 11% | 9% | 6% | 5% | 5% | 4% | 5% | 5% | 6% | 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: High Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 82% | 84% | 86% | 88% | 91% | 93% | 92% | 93% | 92% | 92% | 91% | 93% | 92% | 92% | 92% |
| 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 | 1% | 3% | 8% | 17% | 15% | 13% | 11% | 7% | 6% | 7% | 6% | 6% | 7% | 8% | 6% | 7% | 7% | 7% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: High Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 84% | 87% | 90% | 92% | 95% | 96% | 95% | 96% | 95% | 95% | 95% | 96% | 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 | 1% | 3% | 8% | 15% | 12% | 9% | 7% | 4% | 3% | 4% | 3% | 3% | 3% | 4% | 3% | 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: Low Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 78% | 79% | 80% | 82% | 82% | 81% | 81% | 82% | 82% | 81% | 80% | 81% | 83% | 74% | 67% |
| 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 | 1% | 3% | 8% | 21% | 20% | 19% | 17% | 17% | 18% | 18% | 17% | 17% | 18% | 19% | 17% | 16% | 25% | 32% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: Low Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 77% | 78% | 79% | 81% | 82% | 75% | 70% | 71% | 70% | 69% | 68% | 69% | 73% | 69% | 67% |
| 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 | 1% | 3% | 8% | 22% | 21% | 20% | 18% | 17% | 24% | 29% | 27% | 29% | 30% | 31% | 30% | 26% | 30% | 32% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

| Scenario: Low Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 98% | 96% | 91% | 79% | 79% | 80% | 82% | 82% | 81% | 81% | 81% | 82% | 81% | 80% | 81% | 83% | 81% | 81% |
| 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 | 1% | 3% | 8% | 21% | 20% | 19% | 17% | 17% | 18% | 18% | 18% | 17% | 18% | 19% | 18% | 16% | 18% | 18% |
| 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% | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| 2. Other | 7% | 9% | 7% | 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** | 62% | 64% | 62% | 58% | 58% | 58% | 59% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% | 58% |

*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

**Kentucky Utilities Company and Louisville Gas and Electric Company** Sch4

**POWER SUPPLY DATA**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **I. Capability (MW)** | | | | | | | | | | | | | | | | | | |
| **1. Summer** | | | | | | | | | | | | | | | | | | |
| a. Installed Net Dependable Capability (1) | 7,905 | 7,911 | 7,852 | 7,847 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 | 7,851 |
| b. Total Positive Interchange commitments (2) | 179 | 179 | 337 | 337 | 337 | 337 | 172 | 172 | 172 | 172 | 172 | 172 | 172 | 172 | 172 | 172 | 172 | 172 |
| 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) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Total Net Summer Capabilty (a+b+c+d) | 8,084 | 8,090 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 |
| **2. Winter (3)** | | | | | | | | | | | | | | | | | | |
| a. Installed Net Dependable Capability (1) | 8,180 | 8,187 | 8,146 | 8,085 | 8,080 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 | 8,084 |
| b. Total Positive Interchange commitments (2) | 179 | 179 | 178 | 343 | 343 | 343 | 343 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| 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) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Total Net Winter Capabilty (a+b+c+d) | 8,359 | 8,366 | 8,324 | 8,428 | 8,423 | 8,427 | 8,427 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 |

(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) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014, etc.

(4) all DSM demand response and energy efficiency included in Adjusted Load - see Sch 1

**Kentucky Utilities Company and Louisville Gas and Electric Company** Sch5

**POWER SUPPLY DATA (cont.)**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **II. Load (MW)** | | | | | | | | | | | | | | | | | | |
| 1. Summer | | | | | | | | | | | | | | | | | | |
| a. Adjusted Summer Peak (1) | 6,434 | 6,313 | 6,392 | 6,948 | 6,988 | 7,004 | 6,744 | 6,754 | 6,786 | 6,820 | 6,852 | 6,874 | 6,891 | 6,918 | 6,946 | 6,977 | 7,005 | 7,033 |
| 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 | 6,434 | 6,313 | 6,392 | 6,948 | 6,988 | 7,004 | 6,744 | 6,754 | 6,786 | 6,820 | 6,852 | 6,874 | 6,891 | 6,918 | 6,946 | 6,977 | 7,005 | 7,033 |
| d. Percent Increase in Total Summer Peak | | -1.9% | 1.2% | 8.7% | 0.6% | 0.2% | -3.7% | 0.2% | 0.5% | 0.5% | 0.5% | 0.3% | 0.2% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| 2. Winter (3) | | | | | | | | | | | | | | | | | | |
| a. Adjusted Winter Peak (1) | 5,907 | 7,114 | 7,079 | 6,090 | 6,127 | 6,135 | 6,153 | 5,897 | 5,908 | 5,925 | 5,944 | 5,971 | 5,983 | 6,003 | 6,025 | 6,054 | 6,082 | 6,110 |
| 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) | 5,907 | 7,114 | 7,079 | 6,090 | 6,127 | 6,135 | 6,153 | 5,897 | 5,908 | 5,925 | 5,944 | 5,971 | 5,983 | 6,003 | 6,025 | 6,054 | 6,082 | 6,110 |
| d. Percent Increase in Total Winter Peak | | 20.4% | -0.5% | -14.0% | 0.6% | 0.1% | 0.3% | -4.2% | 0.2% | 0.3% | 0.3% | 0.4% | 0.2% | 0.3% | 0.4% | 0.5% | 0.5% | 0.4% |

(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.)

Kentucky Utilities Company and Louisville Gas and Electric Company  Sch6

POWER SUPPLY DATA (continued)

| Scenario: Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| I. Reserve Margin | | | | | | | | | | | | | | | | | | |
| (Including Cold Reserve Capability) (1) | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 1,236 | 1,200 | 1,183 | 1,279 | 1,268 | 1,236 | 1,203 | 1,170 | 1,149 | 1,132 | 1,105 | 1,077 | 1,046 | 1,017 | 989 |
| b. Percent of Load | 23% | 28% | 28% | 18% | 17% | 17% | 19% | 19% | 18% | 18% | 17% | 17% | 16% | 16% | 16% | 15% | 15% | 14% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,338 | 2,296 | 2,292 | 2,273 | 2,364 | 2,353 | 2,336 | 2,317 | 2,291 | 2,279 | 2,259 | 2,236 | 2,208 | 2,179 | 2,152 |
| b. Percent of Load | 38% | 18% | 18% | 38% | 37% | 37% | 37% | 40% | 40% | 39% | 39% | 38% | 38% | 38% | 37% | 36% | 36% | 35% |
| II. Reserve Margin | | | | | | | | | | | | | | | | | | |
| (Excluding Cold Reserve Capability) (3) | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 1,236 | 1,200 | 1,183 | 1,279 | 1,268 | 1,236 | 1,203 | 1,170 | 1,149 | 1,132 | 1,105 | 1,077 | 1,046 | 1,017 | 989 |
| b. Percent of Load | 23% | 28% | 28% | 18% | 17% | 17% | 19% | 19% | 18% | 18% | 17% | 17% | 16% | 16% | 16% | 15% | 15% | 14% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,338 | 2,296 | 2,292 | 2,273 | 2,364 | 2,353 | 2,336 | 2,317 | 2,291 | 2,279 | 2,259 | 2,236 | 2,208 | 2,179 | 2,152 |
| b. Percent of Load | 38% | 18% | 18% | 38% | 37% | 37% | 37% | 40% | 40% | 39% | 39% | 38% | 38% | 38% | 37% | 36% | 36% | 35% |

| Scenario: High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| I. Reserve Margin | | | | | | | | | | | | | | | | | | |
| (Including Cold Reserve Capability) (1) | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 907 | 867 | 846 | 943 | 932 | 900 | 867 | 834 | 813 | 796 | 768 | 739 | 707 | 677 | 647 |
| b. Percent of Load | 23% | 28% | 28% | 12% | 12% | 12% | 13% | 13% | 13% | 12% | 12% | 11% | 11% | 11% | 10% | 10% | 9% | 9% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,036 | 1,989 | 1,980 | 1,945 | 2,052 | 2,043 | 2,027 | 2,009 | 1,984 | 1,974 | 1,955 | 1,934 | 1,906 | 1,877 | 1,850 |
| b. Percent of Load | 38% | 18% | 18% | 32% | 31% | 31% | 30% | 33% | 33% | 33% | 32% | 32% | 31% | 31% | 31% | 30% | 29% | 29% |
| II. Reserve Margin | | | | | | | | | | | | | | | | | | |
| (Excluding Cold Reserve Capability) (3) | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 907 | 867 | 846 | 943 | 932 | 900 | 867 | 834 | 813 | 796 | 768 | 739 | 707 | 677 | 647 |

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| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| b. Percent of Load | 23% | 28% | 28% | 12% | 12% | 12% | 13% | 13% | 13% | 12% | 12% | 11% | 11% | 11% | 10% | 10% | 9% | 9% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,036 | 1,989 | 1,980 | 1,945 | 2,052 | 2,043 | 2,027 | 2,009 | 1,984 | 1,974 | 1,955 | 1,934 | 1,906 | 1,877 | 1,850 |
| b. Percent of Load | 38% | 18% | 18% | 32% | 31% | 31% | 30% | 33% | 33% | 33% | 32% | 32% | 31% | 31% | 31% | 30% | 29% | 29% |

| Scenario: Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **I. Reserve Margin** | | | | | | | | | | | | | | | | | | |
| **(Including Cold Reserve Capability) (1)** | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 1,564 | 1,533 | 1,521 | 1,614 | 1,604 | 1,572 | 1,539 | 1,506 | 1,484 | 1,468 | 1,441 | 1,414 | 1,384 | 1,358 | 1,332 |
| b. Percent of Load | 23% | 28% | 28% | 24% | 23% | 23% | 25% | 25% | 24% | 24% | 23% | 23% | 22% | 22% | 21% | 21% | 20% | 20% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,639 | 2,603 | 2,604 | 2,602 | 2,676 | 2,664 | 2,645 | 2,625 | 2,597 | 2,584 | 2,562 | 2,539 | 2,510 | 2,481 | 2,454 |
| b. Percent of Load | 38% | 18% | 18% | 46% | 45% | 45% | 45% | 48% | 48% | 47% | 47% | 46% | 46% | 45% | 44% | 44% | 43% | 42% |
| **II. Reserve Margin** | | | | | | | | | | | | | | | | | | |
| **(Excluding Cold Reserve Capability) (3)** | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | |
| a. MW | 1,471 | 1,777 | 1,797 | 1,564 | 1,533 | 1,521 | 1,614 | 1,604 | 1,572 | 1,539 | 1,506 | 1,484 | 1,468 | 1,441 | 1,414 | 1,384 | 1,358 | 1,332 |
| b. Percent of Load | 23% | 28% | 28% | 24% | 23% | 23% | 25% | 25% | 24% | 24% | 23% | 23% | 22% | 22% | 21% | 21% | 20% | 20% |
| 2. Winter Reserve Margin (2) | | | | | | | | | | | | | | | | | | |
| a. MW | 2,273 | 1,252 | 1,245 | 2,639 | 2,603 | 2,604 | 2,602 | 2,676 | 2,664 | 2,645 | 2,625 | 2,597 | 2,584 | 2,562 | 2,539 | 2,510 | 2,481 | 2,454 |
| b. Percent of Load | 38% | 18% | 18% | 46% | 45% | 45% | 45% | 48% | 48% | 47% | 47% | 46% | 46% | 45% | 44% | 44% | 43% | 42% |

**III. Annual Loss-of-Load Hours**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario:** | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Mid Gas - Base Load** | Not Applicable | | | 2 | 2 | 2 | 2 | 1 | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 5 | 0 | 0 |
| **Mid Gas - High Load** | Not Applicable | | | 7 | 7 | 7 | 6 | 5 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| **Mid Gas - Low Load** | Not Applicable | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **High Gas - Base Load** | Not Applicable | | | 2 | 2 | 2 | 2 | 1 | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 5 | 2 | 3 |
| **High Gas - High Load** | Not Applicable | | | 7 | 7 | 7 | 6 | 5 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| **High Gas - Low Load** | Not Applicable | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Low Gas - Base Load** | Not Applicable | | | 2 | 2 | 2 | 2 | 1 | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 5 | 0 | 0 |
| **Low Gas - High Load** | Not Applicable | | | 7 | 7 | 7 | 6 | 5 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| **Low Gas - Low Load** | Not Applicable | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

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

(2) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014 etc.

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

Kentucky Utilities Company and Louisville Gas and Electric Company Sch7

Capacity Data

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **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 | 5,742 | 5,736 | 5,170 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 | 5,157 |
| 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 | 2,085 | 2,927 | 2,927 | 2,927 | 2,927 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 | 2,762 |
| f. Hydro-Conventional | 86 | 88 | 92 | 92 | 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 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| i. Total (sum of a through h) | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 |
| **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% | 73% | 63% | 63% | 63% | 63% | 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% | 26% | 36% | 36% | 36% | 36% | 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% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 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 capability during peak season; unit capabilities to be classified by primary fuel type; for winter peaking utilities-2013 refers to the winter of 2013/2014 etc.

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

**Equivalent Availability Factor (%)**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Unit Name** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| Brown 1 | 91.0 | 91.1 | 72.5 | 85.9 | 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 |
| Brown 2 | 88.8 | 84.3 | 95.4 | 85.9 | 87.7 | 77.2 | 89.4 | 87.7 | 89.4 | 87.7 | 89.4 | 77.2 | 89.4 | 85.9 | 89.4 | 85.9 | 89.4 | 85.9 |
| Brown 3 | 78.5 | 80.2 | 76.3 | 86.8 | 90.3 | 86.8 | 86.8 | 77.9 | 90.3 | 86.8 | 90.3 | 86.8 | 90.3 | 77.9 | 90.3 | 86.8 | 90.3 | 86.8 |
| Brown 5 | 98.1 | 96.8 | 88.3 | 79.9 | 69.0 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 | 81.5 |
| Brown 6 | 97.3 | 94.6 | 97.7 | 91.4 | 91.4 | 78.8 | 91.4 | 91.4 | 91.4 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 |
| Brown 7 | 97.4 | 95.0 | 98.2 | 91.4 | 91.4 | 91.4 | 78.8 | 91.4 | 91.4 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 | 93.2 |
| Brown 8 | 95.8 | 96.3 | 91.4 | 92.2 | 88.6 | 92.2 | 92.2 | 92.2 | 78.0 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 |
| Brown 9 | 81.9 | 93.9 | 91.5 | 92.2 | 88.6 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 |
| Brown 10 | 99.1 | 94.7 | 80.1 | 92.2 | 88.6 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 |
| Brown 11 | 82.1 | 95.8 | 91.4 | 92.2 | 88.6 | 92.2 | 78.0 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 | 92.2 |
| Cane Run 4 | 72.9 | 86.1 | 77.7 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 86.6 | 87.7 | 79.4 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 81.9 | 71.3 | 57.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 85.8 | 90.4 | 91.3 | 91.3 | 87.7 | 87.7 | 91.3 | 91.3 | 91.3 | 85.9 | 91.3 | 95.0 | 91.3 | 80.4 | 91.3 | 95.0 |
| Cane Run 11 | 98.9 | 99.6 | 93.3 | 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 | 90.1 | 89.6 | 74.6 | 86.8 | 86.8 | 83.2 | 86.8 | 86.8 | 86.8 | 70.8 | 86.8 | 86.8 | 88.6 | 86.8 | 88.6 | 86.8 | 77.9 | 88.6 |
| Ghent 2 | 94.4 | 92.9 | 78.4 | 86.8 | 85.0 | 86.8 | 76.2 | 86.8 | 86.8 | 86.8 | 86.8 | 86.8 | 86.8 | 77.9 | 88.6 | 86.8 | 88.6 | 86.8 |
| Ghent 3 | 86.6 | 80.5 | 84.7 | 85.0 | 86.8 | 77.9 | 83.2 | 86.8 | 86.8 | 86.8 | 86.8 | 85.0 | 77.9 | 86.8 | 88.6 | 86.8 | 88.6 | 86.8 |
| Ghent 4 | 84.7 | 78.1 | 94.6 | 85.0 | 86.8 | 85.0 | 86.8 | 86.8 | 77.9 | 86.8 | 86.8 | 85.0 | 86.8 | 88.6 | 86.8 | 77.9 | 88.6 | 86.8 |
| G. River 3 | 96.6 | 91.2 | 88.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| G. River 4 | 86.5 | 88.3 | 84.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 97.6 | 98.2 | 99.8 | 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 |
| Mill Creek 1 | 70.4 | 90.1 | 77.3 | 90.3 | 85.0 | 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 |
| Mill Creek 2 | 88.5 | 80.7 | 76.7 | 83.2 | 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 | 85.0 |
| Mill Creek 3 | 75.4 | 91.8 | 85.4 | 76.2 | 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 |
| Mill Creek 4 | 80.5 | 66.3 | 89.4 | 83.2 | 90.3 | 85.0 | 90.3 | 85.0 | 90.3 | 77.9 | 90.3 | 85.0 | 90.3 | 85.0 | 90.3 | 85.0 | 90.3 | 77.9 |
| Paddy's Run 11&12 (3) | 94.7 | 96.6 | 76.8 | 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 |
| Paddy's Run 13 | 83.3 | 90.6 | 84.7 | 85.9 | 85.9 | 85.9 | 85.9 | 57.3 | 52.2 | 85.9 | 85.9 | 85.9 | 85.9 | 87.6 | 87.6 | 87.6 | 87.6 | 87.6 |
| Trimble 1 75% | 85.6 | 93.2 | 77.3 | 89.4 | 76.9 | 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 |
| Trimble 2 75% | 66.4 | 60.1 | 85.4 | 82.3 | 85.8 | 75.3 | 82.3 | 82.3 | 85.8 | 82.3 | 85.8 | 82.3 | 82.3 | 75.3 | 82.3 | 82.3 | 82.3 | 82.3 |
| Trimble 5 | 97.3 | 98.6 | 92.9 | 95.5 | 80.8 | 95.5 | 95.5 | 95.5 | 77.1 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Trimble 6 | 98.1 | 97.5 | 93.3 | 80.8 | 95.5 | 95.5 | 95.5 | 77.1 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Trimble 7 | 98.0 | 97.2 | 94.2 | 95.5 | 80.8 | 95.5 | 95.5 | 95.5 | 77.1 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Trimble 8 | 93.0 | 96.6 | 96.4 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 80.8 | 95.5 | 95.5 | 77.1 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Trimble 9 | 97.8 | 95.7 | 95.8 | 95.5 | 95.5 | 80.8 | 95.5 | 95.5 | 95.5 | 77.1 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Trimble 10 | 82.4 | 97.8 | 97.3 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 80.8 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 | 95.5 |
| Zorn 1 | 99.7 | 85.0 | 81.3 | 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 |
| Brown Solar | NA | NA | NA | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

(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.

UNIT PERFORMANCE DATA (1)

Net Capacity Factor (%)

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Unit Name** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **Scenario: Mid Gas - Base Load** | | | | | | | | | | | | | | | | | | |
| E.W. Brown 1 | 40.8 | 40.0 | 22.3 | 15.4 | 20.9 | 21.5 | 21.6 | 16.8 | 21.1 | 21.6 | 32.9 | 37.7 | 45.9 | 42.3 | 42.8 | 42.9 | 37.5 | 43.2 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 15.3 | 18.3 | 17.5 | 19.9 | 16.3 | 21.3 | 26.4 | 31.9 | 32.0 | 41.4 | 40.6 | 40.5 | 40.5 | 44.3 | 41.8 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 6.5 | 10.5 | 12.2 | 11.2 | 8.1 | 12.0 | 14.4 | 17.3 | 22.1 | 27.8 | 24.2 | 29.0 | 29.3 | 32.7 | 31.7 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 0.8 | 0.7 | 1.0 | 0.5 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.2 | 0.2 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 26.9 | 1.7 | 2.0 | 1.1 | 1.0 | 1.0 | 1.1 | 1.0 | 1.1 | 1.1 | 1.3 | 1.2 | 1.5 | 0.4 | 0.3 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 30.5 | 2.3 | 2.7 | 1.4 | 1.4 | 1.4 | 1.6 | 1.3 | 1.7 | 1.8 | 1.8 | 1.7 | 2.4 | 0.6 | 0.5 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.5 | 0.5 | 0.8 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.1 | 0.1 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 0.9 | 0.8 | 0.7 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.1 | 0.1 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 0.7 | 0.6 | 0.5 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.1 | 0.1 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.4 | 0.4 | 0.7 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.1 | 0.1 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 93.4 | 77.3 | 52.6 | 42.6 | 42.6 | 26.9 | 24.0 | 23.1 | 26.6 | 20.6 | 22.5 | 24.0 | 23.0 |
| Cane Run 11 | 0.1 | -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 | 0.0 | 0.0 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 85.0 | 72.5 | 70.7 | 78.3 | 80.7 | 82.3 | 67.8 | 82.3 | 82.6 | 84.7 | 83.6 | 84.9 | 83.5 | 74.8 | 85.5 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 79.8 | 71.1 | 75.4 | 64.0 | 74.3 | 76.3 | 78.0 | 77.8 | 78.8 | 79.6 | 71.1 | 80.9 | 80.1 | 81.5 | 79.8 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 51.1 | 47.1 | 46.5 | 52.0 | 56.0 | 65.6 | 67.8 | 66.0 | 64.6 | 62.3 | 70.5 | 70.4 | 70.6 | 72.4 | 70.7 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 68.0 | 61.4 | 63.0 | 68.2 | 72.7 | 69.8 | 80.3 | 78.3 | 77.1 | 79.5 | 81.9 | 79.6 | 72.3 | 82.5 | 80.8 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 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 | 0.2 | 0.0 | 0.0 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 81.1 | 79.0 | 82.3 | 79.2 | 89.2 | 77.1 | 89.4 | 84.0 | 89.7 | 84.2 | 89.6 | 84.1 | 89.6 | 77.0 | 89.7 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 73.5 | 86.1 | 78.3 | 87.8 | 77.1 | 89.1 | 84.2 | 89.3 | 84.1 | 89.3 | 84.2 | 89.2 | 77.1 | 89.1 | 84.2 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 62.6 | 78.2 | 79.9 | 72.2 | 88.0 | 83.7 | 88.3 | 83.2 | 87.9 | 82.9 | 88.2 | 76.3 | 88.3 | 83.1 | 88.0 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 68.3 | 88.1 | 81.6 | 89.7 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.7 | 78.2 |
| Paddy's Run 11&12 | -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 | 0.0 | 0.0 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 7.0 | 18.7 | 19.0 | 14.2 | 8.6 | 4.9 | 8.3 | 6.5 | 7.9 | 7.6 | 8.6 | 7.1 | 9.1 | 4.9 | 2.6 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 73.0 | 68.6 | 87.0 | 73.5 | 73.8 | 71.0 | 76.4 | 72.8 | 77.7 | 67.6 | 78.8 | 73.9 | 78.9 | 74.8 | 78.9 |
| Trimble County 2 (75%) | 65 | 59 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 10.7 | 10.8 | 17.1 | 11.7 | 10.8 | 7.2 | 10.3 | 7.6 | 8.9 | 8.1 | 9.3 | 7.8 | 10.1 | 5.4 | 3.0 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 7.8 | 11.7 | 13.2 | 8.5 | 6.7 | 7.3 | 7.6 | 5.6 | 6.8 | 6.3 | 7.2 | 6.0 | 7.8 | 3.8 | 2.2 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 6.2 | 8.0 | 10.1 | 6.2 | 6.1 | 5.0 | 5.6 | 4.2 | 5.2 | 4.8 | 5.5 | 4.7 | 6.0 | 2.8 | 1.7 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 4.6 | 6.5 | 7.5 | 4.4 | 4.3 | 4.1 | 3.4 | 3.2 | 3.8 | 3.6 | 4.2 | 3.7 | 4.7 | 2.0 | 1.3 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 3.4 | 4.7 | 5.3 | 3.1 | 3.1 | 2.8 | 2.9 | 2.4 | 2.8 | 2.8 | 3.1 | 2.8 | 3.5 | 1.3 | 0.9 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 2.5 | 3.4 | 4.0 | 2.2 | 2.1 | 2.0 | 2.3 | 1.7 | 2.0 | 2.1 | 2.3 | 2.1 | 2.7 | 0.9 | 0.6 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 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 | 0.0 | 0.0 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 4.9 | 7.1 |

**Sce[illegible] Mid Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 40.8 | 40.0 | 22.3 | 20.7 | 27.5 | 28.0 | 29.[illegible] | [illegible]3.2 | 23.8 | 26.8 | 41.3 | 46.0 | 54.9 | 50.7 | 51.7 | 51.3 | 44.9 | 51.5 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 19.7 | 23.5 | 22.6 | 26.0 | 21.8 | 24.1 | 30.5 | 38.3 | 38.6 | 49.0 | 48.0 | 48.3 | 48.0 | 52.1 | 49.3 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 9.1 | 14.0 | 15.9 | 15.4 | 11.5 | 10.6 | 12.0 | 22.6 | 29.0 | 35.3 | 30.6 | 36.8 | 36.9 | 40.4 | 39.2 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 1.5 | 1.3 | 1.9 | 1.1 | 0.9 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 35.5 | 3.1 | 3.5 | 2.1 | 2.0 | 0.7 | 0.5 | 0.4 | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.6 | 0.7 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 38.9 | 4.0 | 4.7 | 2.5 | 2.5 | 0.9 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 1.0 | 0.8 | 0.9 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 1.0 | 0.9 | 1.5 | 0.8 | 0.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 1.7 | 1.4 | 1.4 | 0.7 | 0.6 | 0.2 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 1.3 | 1.1 | 1.1 | 0.5 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.8 | 0.8 | 1.3 | 0.7 | 0.6 | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 94.1 | 81.0 | 60.8 | 51.9 | 51.3 | 34.7 | 30.8 | 30.8 | 34.2 | 27.5 | 29.1 | 31.3 | 30.3 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 85.5 | 75.9 | 74.2 | 80.7 | 82.3 | 83.6 | 68.7 | 83.7 | 83.9 | 85.9 | 84.7 | 86.0 | 84.7 | 75.8 | 86.5 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 80.8 | 72.9 | 76.9 | 65.9 | 75.9 | 78.0 | 79.5 | 79.6 | 80.4 | 81.2 | 72.5 | 82.5 | 81.5 | 83.0 | 81.2 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 58.5 | 55.2 | 53.5 | 59.0 | 62.1 | 71.3 | 73.3 | 72.1 | 70.7 | 67.2 | 75.7 | 76.0 | 76.1 | 77.6 | 75.9 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 72.9 | 68.5 | 68.8 | 73.2 | 77.2 | 72.6 | 82.8 | 81.5 | 80.1 | 82.3 | 84.6 | 82.4 | 74.4 | 85.0 | 83.4 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 82.1 | 79.9 | 83.5 | 80.2 | 89.4 | 77.3 | 89.6 | 84.2 | 89.8 | 84.4 | 89.7 | 84.3 | 89.7 | 77.1 | 89.8 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 74.9 | 86.9 | 79.3 | 88.3 | 77.1 | 89.3 | 84.2 | 89.4 | 84.2 | 89.4 | 84.2 | 89.3 | 77.2 | 89.3 | 84.2 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 65.1 | 78.9 | 81.4 | 73.2 | 88.6 | 84.1 | 88.9 | 83.8 | 88.6 | 83.5 | 88.8 | 76.8 | 88.9 | 83.7 | 88.7 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 71.9 | 88.9 | 82.7 | 90.0 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.7 | 78.2 |
| Paddy's Run 11&12 | -0.1 | 0.2 | -0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 11.1 | 25.7 | 25.3 | 20.8 | 12.1 | 2.5 | 3.6 | 3.2 | 3.6 | 3.5 | 4.0 | 3.4 | 4.4 | 4.0 | 4.0 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 74.7 | 69.6 | 87.4 | 75.1 | 75.6 | 72.9 | 78.5 | 74.9 | 79.9 | 69.5 | 80.9 | 75.9 | 81.0 | 76.7 | 81.0 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 15.5 | 15.5 | 23.3 | 17.7 | 16.1 | 4.8 | 4.4 | 3.6 | 4.4 | 4.1 | 4.6 | 4.2 | 5.1 | 4.7 | 4.8 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 11.4 | 16.9 | 18.7 | 13.3 | 10.3 | 6.6 | 3.2 | 2.7 | 3.0 | 2.9 | 3.3 | 3.0 | 3.7 | 3.5 | 3.6 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 9.5 | 11.9 | 14.7 | 10.0 | 9.8 | 4.7 | 2.3 | 1.9 | 2.3 | 2.3 | 2.6 | 2.4 | 2.9 | 2.7 | 2.8 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 7.3 | 10.2 | 11.4 | 7.4 | 7.2 | 3.5 | 1.6 | 1.5 | 1.8 | 1.8 | 2.0 | 1.9 | 2.3 | 2.2 | 2.3 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 5.4 | 7.6 | 8.4 | 5.4 | 5.3 | 2.3 | 1.2 | 1.1 | 1.2 | 1.2 | 1.3 | 1.3 | 1.6 | 1.5 | 1.6 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 4.1 | 5.6 | 6.6 | 3.9 | 3.8 | 1.6 | 0.9 | 0.8 | 0.9 | 0.9 | 1.0 | 1.0 | 1.2 | 1.1 | 1.2 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 11.7 | 16.2 | 8.8 | 9.8 | 9.2 | 10.7 | 9.0 | 11.4 | 10.5 | 10.5 |

**Sce[illegible] Mid Gas - Low Load**

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. [illegible]n 1 | 40.8 | 40.0 | 22.3 | 11.0 | 15.1 | 15.7 | 15.[illegible] | [illegible]1.5 | 14.8 | 15.6 | 24.7 | 29.6 | 36.5 | 33.6 | 33.7 | 34.3 | 29.9 | 34.6 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 11.4 | 13.6 | 13.0 | 14.4 | 11.4 | 15.7 | 20.1 | 25.1 | 25.5 | 33.6 | 33.1 | 32.6 | 33.0 | 36.3 | 34.1 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 4.4 | 7.5 | 8.9 | 7.7 | 5.5 | 8.0 | 9.9 | 12.1 | 16.5 | 21.2 | 18.5 | 22.0 | 22.5 | 25.3 | 24.5 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 0.4 | 0.4 | 0.5 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.3 | 0.4 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 19.2 | 0.9 | 1.0 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 | 0.7 | 0.8 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 22.7 | 1.2 | 1.5 | 0.7 | 0.7 | 0.7 | 0.8 | 0.6 | 0.9 | 1.0 | 0.9 | 0.9 | 1.3 | 1.0 | 1.1 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.2 | 0.2 | 0.4 | 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 9 | 0.5 | 1.6 | 8.4 | 0.4 | 0.4 | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 0.3 | 0.3 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.2 | 0.2 | 0.3 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 92.2 | 73.1 | 43.8 | 33.4 | 33.9 | 19.9 | 17.7 | 16.3 | 19.5 | 14.6 | 16.5 | 17.4 | 16.7 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 84.3 | 67.9 | 66.1 | 75.1 | 78.6 | 80.3 | 66.4 | 80.3 | 80.6 | 82.9 | 82.0 | 83.3 | 81.8 | 73.5 | 84.0 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 78.6 | 69.0 | 73.7 | 62.0 | 72.7 | 74.4 | 76.4 | 75.8 | 76.9 | 77.6 | 69.6 | 79.0 | 78.5 | 79.8 | 78.1 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 43.3 | 38.8 | 39.2 | 44.0 | 49.1 | 58.5 | 60.7 | 58.4 | 57.3 | 56.0 | 63.9 | 63.2 | 63.7 | 65.8 | 64.0 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 61.7 | 52.8 | 55.9 | 61.8 | 66.8 | 65.8 | 76.5 | 73.8 | 72.7 | 75.5 | 77.9 | 75.6 | 68.9 | 78.9 | 76.9 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 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 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 80.0 | 78.1 | 81.1 | 78.2 | 88.9 | 77.0 | 89.2 | 83.8 | 89.6 | 84.0 | 89.4 | 83.9 | 89.5 | 76.8 | 89.6 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 72.0 | 85.2 | 77.2 | 87.2 | 77.0 | 88.9 | 84.0 | 89.2 | 84.1 | 89.2 | 84.1 | 89.1 | 77.0 | 89.0 | 84.1 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 59.8 | 77.4 | 78.5 | 71.3 | 87.4 | 83.0 | 87.5 | 82.5 | 87.0 | 82.1 | 87.4 | 75.7 | 87.5 | 82.4 | 87.2 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 63.6 | 87.0 | 80.1 | 89.3 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.6 | 78.2 |
| Paddy's Run 11&12 | -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 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 4.1 | 12.9 | 13.6 | 9.1 | 5.8 | 3.2 | 5.4 | 4.2 | 5.2 | 4.9 | 5.7 | 4.6 | 6.1 | 5.5 | 5.6 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 71.3 | 67.5 | 86.5 | 71.8 | 72.1 | 68.9 | 74.2 | 70.6 | 75.4 | 65.5 | 76.5 | 71.6 | 76.5 | 72.6 | 76.5 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 7.0 | 7.1 | 11.8 | 7.2 | 6.7 | 4.5 | 6.5 | 4.7 | 5.7 | 5.1 | 5.9 | 5.0 | 6.5 | 6.0 | 5.9 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 4.9 | 7.5 | 8.8 | 5.1 | 4.1 | 4.3 | 4.6 | 3.4 | 4.2 | 3.8 | 4.4 | 3.7 | 4.9 | 4.4 | 4.4 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 3.8 | 5.0 | 6.4 | 3.5 | 3.5 | 2.9 | 3.3 | 2.4 | 3.1 | 2.8 | 3.2 | 2.8 | 3.7 | 3.4 | 3.6 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 2.7 | 3.9 | 4.6 | 2.4 | 2.4 | 2.3 | 1.9 | 1.8 | 2.2 | 2.1 | 2.4 | 2.1 | 2.7 | 2.5 | 2.6 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 1.9 | 2.7 | 3.1 | 1.6 | 1.6 | 1.5 | 1.6 | 1.3 | 1.6 | 1.5 | 1.7 | 1.6 | 2.0 | 1.8 | 1.9 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 1.4 | 1.8 | 2.2 | 1.1 | 1.1 | 1.0 | 1.2 | 0.9 | 1.1 | 1.1 | 1.3 | 1.2 | 1.5 | 1.4 | 1.5 |
| Zorn 1 | 0.2 | 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 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |

**Sce[illegible] High Gas - Base Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. [illegible]n 1 | 40.8 | 40.0 | 22.3 | 22.7 | 23.0 | 23.5 | 26.[illegible] | [illegible]3.8 | 42.3 | 38.0 | 39.8 | 39.4 | 45.9 | 42.3 | 42.8 | 42.9 | 37.5 | 43.2 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 19.6 | 20.0 | 18.2 | 26.0 | 32.5 | 38.4 | 42.3 | 38.3 | 33.8 | 43.4 | 42.7 | 41.5 | 41.8 | 44.8 | 42.0 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 12.8 | 13.5 | 14.6 | 14.4 | 17.1 | 28.3 | 32.4 | 28.0 | 28.0 | 32.3 | 27.3 | 31.1 | 31.5 | 34.0 | 31.9 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 0.7 | 0.6 | 0.8 | 0.5 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.5 | 0.5 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 13.9 | 1.6 | 1.8 | 1.0 | 0.9 | 1.0 | 1.1 | 1.0 | 1.1 | 1.1 | 1.3 | 1.2 | 1.5 | 1.4 | 1.5 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 15.6 | 2.0 | 2.5 | 1.3 | 1.3 | 1.3 | 1.6 | 1.3 | 1.7 | 1.8 | 1.7 | 1.7 | 2.4 | 1.9 | 1.9 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.5 | 0.4 | 0.6 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.4 | 0.5 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 0.7 | 0.6 | 0.6 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.4 | 0.4 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 0.6 | 0.5 | 0.5 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.3 | 0.3 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.4 | 0.4 | 0.5 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.4 | 0.4 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 84.1 | 71.1 | 52.8 | 43.1 | 25.1 | 19.3 | 21.0 | 17.0 | 19.4 | 19.7 | 24.1 | 19.0 | 20.8 | 22.9 | 22.9 |
| Cane Run 11 | 0.1 | -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 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 85.1 | 77.5 | 80.2 | 83.9 | 81.8 | 82.6 | 67.9 | 82.3 | 82.6 | 84.7 | 83.6 | 84.9 | 83.5 | 74.8 | 85.5 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 80.6 | 74.1 | 78.4 | 67.6 | 77.5 | 78.3 | 79.6 | 78.1 | 78.9 | 79.6 | 71.1 | 80.9 | 80.1 | 81.5 | 79.8 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 57.3 | 59.3 | 65.4 | 67.1 | 66.3 | 68.8 | 69.5 | 66.1 | 64.9 | 62.4 | 70.6 | 70.4 | 70.7 | 72.5 | 70.7 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 70.2 | 70.5 | 79.1 | 80.1 | 76.9 | 69.8 | 80.3 | 78.3 | 77.1 | 79.5 | 81.9 | 79.6 | 72.3 | 82.5 | 80.8 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 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 | 0.2 | 0.1 | 0.1 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 81.6 | 80.1 | 83.9 | 81.7 | 89.6 | 77.1 | 89.6 | 84.0 | 89.7 | 84.2 | 89.6 | 84.1 | 89.6 | 77.0 | 89.7 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 74.1 | 87.2 | 79.6 | 88.9 | 77.1 | 89.1 | 84.2 | 89.3 | 84.1 | 89.3 | 84.2 | 89.2 | 77.1 | 89.1 | 84.2 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 63.3 | 79.0 | 82.9 | 74.4 | 88.5 | 83.7 | 88.4 | 83.2 | 87.9 | 82.9 | 88.2 | 76.3 | 88.2 | 83.1 | 88.0 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 72.6 | 89.5 | 84.4 | 90.6 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.7 | 78.2 |
| Paddy's Run 11&12 | -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 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 5.4 | 14.1 | 14.0 | 8.3 | 6.2 | 4.8 | 8.3 | 6.6 | 7.9 | 7.8 | 8.7 | 7.2 | 9.4 | 8.5 | 8.3 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 75.0 | 69.2 | 87.9 | 76.5 | 77.4 | 73.7 | 78.9 | 73.2 | 77.9 | 67.5 | 78.7 | 73.8 | 78.8 | 74.7 | 78.9 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 8.7 | 9.5 | 15.7 | 10.4 | 8.9 | 6.1 | 9.0 | 6.9 | 8.4 | 7.9 | 9.3 | 7.7 | 9.9 | 9.1 | 9.0 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 6.2 | 9.1 | 12.2 | 7.4 | 5.8 | 6.4 | 6.9 | 5.3 | 6.6 | 6.1 | 7.1 | 6.0 | 7.7 | 7.1 | 7.0 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 5.0 | 6.2 | 9.4 | 5.5 | 5.0 | 4.6 | 5.1 | 4.0 | 5.2 | 4.8 | 5.7 | 4.9 | 6.2 | 5.7 | 5.8 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 3.6 | 5.3 | 7.0 | 4.0 | 3.7 | 3.7 | 3.1 | 3.1 | 3.8 | 3.5 | 4.2 | 3.7 | 4.6 | 4.2 | 4.3 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 2.6 | 3.8 | 4.9 | 2.8 | 2.6 | 2.7 | 2.8 | 2.3 | 2.8 | 2.8 | 3.1 | 2.8 | 3.5 | 3.2 | 3.3 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 1.9 | 2.7 | 3.7 | 2.0 | 1.9 | 1.9 | 2.3 | 1.7 | 2.0 | 2.1 | 2.3 | 2.1 | 2.7 | 2.5 | 2.6 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 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 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| SCCT | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 0.7 | 0.8 |

**Sce[illegible]High Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W.[illegible]n 1 | 40.8 | 40.0 | 22.3 | 29.6 | 30.4 | 30.6 | 34.[illegible] | [illegible]1.9 | 51.5 | 45.5 | 48.9 | 47.9 | 54.9 | 50.7 | 51.7 | 51.3 | 44.9 | 51.5 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 25.0 | 25.8 | 23.6 | 32.8 | 39.4 | 46.3 | 50.0 | 46.3 | 40.6 | 51.3 | 50.4 | 49.4 | 49.4 | 52.6 | 49.5 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 16.9 | 18.2 | 19.6 | 20.1 | 22.4 | 36.1 | 40.1 | 35.7 | 35.3 | 40.4 | 33.9 | 39.0 | 39.1 | 42.0 | 39.4 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 1.4 | 1.2 | 1.6 | 0.9 | 0.9 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 20.0 | 2.8 | 3.2 | 1.9 | 1.8 | 0.7 | 0.5 | 0.4 | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.6 | 0.7 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 21.7 | 3.4 | 4.3 | 2.3 | 2.4 | 0.9 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 1.0 | 0.8 | 0.9 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.9 | 0.9 | 1.2 | 0.8 | 0.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 1.3 | 1.2 | 1.2 | 0.6 | 0.6 | 0.2 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 1.1 | 1.0 | 1.0 | 0.5 | 0.5 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.8 | 0.8 | 1.1 | 0.6 | 0.6 | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 86.8 | 77.1 | 61.3 | 52.2 | 32.7 | 26.3 | 28.0 | 23.3 | 25.8 | 26.7 | 31.4 | 25.7 | 27.1 | 30.0 | 30.2 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 85.6 | 79.3 | 81.2 | 84.8 | 83.4 | 83.9 | 68.8 | 83.7 | 83.9 | 85.9 | 84.7 | 86.0 | 84.7 | 75.8 | 86.5 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 81.6 | 75.5 | 79.6 | 69.0 | 79.3 | 80.1 | 81.1 | 79.9 | 80.5 | 81.2 | 72.5 | 82.5 | 81.5 | 83.0 | 81.2 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 63.7 | 65.3 | 69.4 | 72.0 | 72.2 | 74.6 | 75.0 | 72.2 | 70.9 | 67.3 | 75.8 | 76.0 | 76.2 | 77.6 | 75.9 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 74.3 | 74.7 | 81.4 | 82.8 | 80.5 | 72.6 | 82.8 | 81.5 | 80.1 | 82.3 | 84.6 | 82.4 | 74.4 | 85.0 | 83.4 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 82.7 | 80.9 | 85.0 | 82.5 | 89.7 | 77.3 | 89.7 | 84.2 | 89.8 | 84.4 | 89.7 | 84.3 | 89.7 | 77.1 | 89.8 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 75.5 | 87.8 | 80.5 | 89.2 | 77.2 | 89.3 | 84.2 | 89.4 | 84.2 | 89.4 | 84.2 | 89.3 | 77.2 | 89.3 | 84.2 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 65.7 | 79.7 | 84.3 | 75.3 | 89.1 | 84.1 | 89.0 | 83.8 | 88.6 | 83.5 | 88.8 | 76.8 | 88.8 | 83.7 | 88.7 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 75.0 | 89.8 | 84.7 | 90.7 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.7 | 78.2 |
| Paddy's Run 11&12 | -0.1 | 0.2 | -0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 8.9 | 20.1 | 18.7 | 12.2 | 8.8 | 2.6 | 3.8 | 3.1 | 3.6 | 3.5 | 4.0 | 3.4 | 4.4 | 4.0 | 4.0 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 76.7 | 70.1 | 88.0 | 78.0 | 79.6 | 75.8 | 81.0 | 75.3 | 80.1 | 69.4 | 80.8 | 75.8 | 81.0 | 76.7 | 81.0 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 13.0 | 13.6 | 21.5 | 15.6 | 13.4 | 4.6 | 4.5 | 3.7 | 4.3 | 4.1 | 4.6 | 4.2 | 5.1 | 4.7 | 4.8 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 9.3 | 13.6 | 17.2 | 11.6 | 8.9 | 6.0 | 3.1 | 2.6 | 3.0 | 2.9 | 3.3 | 3.0 | 3.7 | 3.5 | 3.6 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 7.8 | 9.4 | 13.8 | 8.9 | 8.1 | 4.3 | 2.3 | 2.1 | 2.3 | 2.3 | 2.6 | 2.4 | 2.9 | 2.7 | 2.8 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 5.9 | 8.4 | 10.6 | 6.6 | 6.2 | 3.3 | 1.6 | 1.6 | 1.8 | 1.8 | 2.0 | 1.9 | 2.3 | 2.2 | 2.3 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 4.4 | 6.1 | 7.8 | 4.8 | 4.6 | 2.2 | 1.2 | 1.1 | 1.2 | 1.2 | 1.3 | 1.3 | 1.6 | 1.5 | 1.6 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 3.2 | 4.6 | 6.2 | 3.6 | 3.4 | 1.5 | 0.9 | 0.8 | 0.9 | 0.9 | 1.0 | 1.0 | 1.2 | 1.1 | 1.2 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 6.0 | 10.1 | 8.1 | 9.7 | 9.4 | 10.7 | 9.1 | 11.5 | 10.6 | 10.4 |

**Sce[illegible] High Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 40.8 | 40.0 | 22.3 | 16.5 | 16.5 | 17.2 | 18.[illegible] | 26.0 | 32.9 | 30.2 | 30.7 | 31.0 | 36.5 | 33.6 | 33.7 | 34.3 | 29.9 | 34.6 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 14.7 | 14.7 | 13.3 | 19.6 | 25.7 | 30.5 | 34.2 | 30.3 | 26.8 | 35.1 | 34.8 | 33.4 | 34.0 | 36.7 | 34.2 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 9.2 | 9.5 | 10.4 | 9.7 | 12.4 | 21.2 | 24.9 | 20.8 | 21.1 | 24.6 | 21.0 | 23.6 | 24.2 | 26.4 | 24.7 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 0.4 | 0.3 | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.3 | 0.4 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 9.1 | 0.8 | 0.9 | 0.5 | 0.4 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 | 0.7 | 0.8 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 10.6 | 1.1 | 1.3 | 0.6 | 0.6 | 0.7 | 0.8 | 0.7 | 0.9 | 1.0 | 0.9 | 0.9 | 1.3 | 1.0 | 1.1 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.2 | 0.2 | 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 9 | 0.5 | 1.6 | 8.4 | 0.3 | 0.3 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 0.3 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 81.1 | 64.4 | 43.7 | 33.9 | 18.2 | 13.4 | 14.8 | 11.7 | 14.0 | 13.8 | 17.5 | 13.3 | 15.1 | 16.6 | 16.6 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 84.3 | 75.2 | 78.8 | 82.6 | 79.6 | 80.6 | 66.5 | 80.3 | 80.6 | 82.9 | 82.0 | 83.3 | 81.8 | 73.5 | 84.0 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 79.6 | 72.7 | 77.1 | 66.1 | 75.5 | 76.2 | 77.8 | 76.1 | 76.9 | 77.6 | 69.6 | 79.0 | 78.5 | 79.8 | 78.1 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 49.9 | 52.2 | 60.1 | 60.7 | 58.9 | 61.5 | 62.4 | 58.5 | 57.5 | 56.1 | 64.0 | 63.3 | 63.8 | 65.8 | 64.0 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 65.1 | 65.1 | 75.8 | 76.2 | 71.8 | 65.8 | 76.5 | 73.8 | 72.7 | 75.5 | 77.9 | 75.6 | 68.9 | 78.9 | 76.9 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 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 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 80.5 | 79.3 | 82.7 | 80.7 | 89.4 | 77.0 | 89.4 | 83.8 | 89.6 | 84.0 | 89.4 | 83.9 | 89.5 | 76.8 | 89.6 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 72.4 | 86.6 | 78.7 | 88.6 | 77.0 | 88.9 | 84.0 | 89.2 | 84.1 | 89.2 | 84.1 | 89.1 | 77.0 | 89.0 | 84.1 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 60.7 | 78.4 | 81.4 | 73.4 | 87.8 | 83.0 | 87.6 | 82.5 | 87.0 | 82.1 | 87.4 | 75.7 | 87.4 | 82.4 | 87.2 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 69.5 | 89.1 | 84.0 | 90.5 | 85.3 | 90.7 | 78.1 | 90.7 | 85.3 | 90.7 | 85.3 | 90.7 | 85.4 | 90.6 | 78.2 |
| Paddy's Run 11&12 | -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 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 3.0 | 9.4 | 10.0 | 5.3 | 4.0 | 3.1 | 5.4 | 4.2 | 5.2 | 5.1 | 5.8 | 4.7 | 6.3 | 5.6 | 5.5 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 73.4 | 68.4 | 87.7 | 74.9 | 75.1 | 71.4 | 76.5 | 71.0 | 75.6 | 65.5 | 76.4 | 71.6 | 76.5 | 72.6 | 76.5 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 5.5 | 6.2 | 10.8 | 6.4 | 5.5 | 3.8 | 5.6 | 4.3 | 5.3 | 5.0 | 5.9 | 4.9 | 6.4 | 5.8 | 5.8 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 3.8 | 5.7 | 8.1 | 4.4 | 3.5 | 3.8 | 4.1 | 3.2 | 4.0 | 3.7 | 4.4 | 3.7 | 4.8 | 4.4 | 4.4 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 3.0 | 3.8 | 6.0 | 3.1 | 2.9 | 2.6 | 2.9 | 2.3 | 3.1 | 2.9 | 3.4 | 3.0 | 3.8 | 3.5 | 3.6 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 2.1 | 3.1 | 4.2 | 2.2 | 2.0 | 2.0 | 1.8 | 1.8 | 2.2 | 2.1 | 2.4 | 2.1 | 2.7 | 2.5 | 2.6 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 1.5 | 2.1 | 2.8 | 1.4 | 1.4 | 1.4 | 1.5 | 1.3 | 1.5 | 1.5 | 1.7 | 1.6 | 2.0 | 1.8 | 1.9 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 1.0 | 1.5 | 2.0 | 1.0 | 0.9 | 1.0 | 1.2 | 0.9 | 1.1 | 1.1 | 1.3 | 1.2 | 1.5 | 1.4 | 1.5 |
| Zorn 1 | 0.2 | 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 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |

**Sce[illegible]Low Gas - Base Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W.[illegible]n 1 | 40.8 | 40.0 | 22.3 | 3.5 | 5.8 | 20.3 | 21.[illegible] | [illegible]6.0 | 18.2 | 17.2 | 17.1 | 19.0 | 21.2 | 18.3 | 19.6 | 23.2 | 9.4 | 6.9 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 4.6 | 8.4 | 16.9 | 19.7 | 15.6 | 16.8 | 19.2 | 16.3 | 16.2 | 19.5 | 17.9 | 18.3 | 20.1 | 12.5 | 6.6 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 0.7 | 1.7 | 10.0 | 11.1 | 7.7 | 9.5 | 11.1 | 8.9 | 9.6 | 10.5 | 9.0 | 10.3 | 11.7 | 6.8 | 3.6 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 1.8 | 0.8 | 1.1 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.8 | 0.7 | 0.8 | 0.2 | 0.2 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 33.9 | 3.6 | 2.4 | 1.1 | 1.0 | 1.1 | 1.3 | 1.1 | 1.3 | 1.3 | 1.4 | 1.4 | 1.7 | 0.5 | 0.4 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 37.0 | 5.1 | 3.3 | 1.4 | 1.4 | 1.5 | 1.8 | 1.4 | 1.7 | 2.2 | 2.0 | 1.9 | 2.8 | 0.7 | 0.5 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.9 | 0.5 | 0.9 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.2 | 0.2 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 1.5 | 0.9 | 0.7 | 0.4 | 0.3 | 0.3 | 0.4 | 0.3 | 0.4 | 0.4 | 0.5 | 0.5 | 0.6 | 0.1 | 0.1 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 1.1 | 0.7 | 0.6 | 0.3 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.5 | 0.1 | 0.1 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.7 | 0.4 | 0.7 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.1 | 0.1 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 95.1 | 91.0 | 91.2 | 95.1 | 95.1 | 95.1 | 89.2 | 95.1 | 99.5 | 95.1 | 83.2 | 95.1 | 99.5 |
| Cane Run 11 | 0.1 | -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 | 0.0 | 0.0 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 84.1 | 71.0 | 70.1 | 76.2 | 70.4 | 69.4 | 58.5 | 69.2 | 72.1 | 73.3 | 71.7 | 74.4 | 75.7 | 52.5 | 52.0 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 78.5 | 69.6 | 75.0 | 63.8 | 70.3 | 70.0 | 71.9 | 70.0 | 71.9 | 71.8 | 64.6 | 73.6 | 74.8 | 67.7 | 61.6 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 51.4 | 45.5 | 45.2 | 44.8 | 41.1 | 42.2 | 43.7 | 40.2 | 40.1 | 38.3 | 44.2 | 44.2 | 49.0 | 34.1 | 20.0 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 68.0 | 61.4 | 61.4 | 61.4 | 55.4 | 51.6 | 60.3 | 56.0 | 56.5 | 59.2 | 60.7 | 57.9 | 54.7 | 50.2 | 25.4 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 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 | 0.2 | 0.0 | 0.0 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 79.1 | 78.6 | 81.9 | 78.8 | 88.2 | 75.7 | 88.0 | 82.4 | 88.7 | 83.0 | 88.0 | 83.0 | 89.0 | 75.0 | 85.9 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 71.6 | 85.7 | 78.2 | 87.2 | 76.4 | 87.8 | 83.1 | 88.3 | 83.5 | 88.4 | 83.5 | 88.2 | 76.7 | 87.5 | 82.0 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 61.6 | 77.6 | 79.8 | 71.6 | 85.7 | 81.1 | 85.2 | 80.3 | 85.0 | 79.7 | 84.9 | 73.6 | 85.5 | 78.6 | 81.3 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 66.8 | 87.9 | 81.5 | 89.2 | 84.9 | 90.2 | 77.8 | 90.2 | 85.1 | 90.3 | 85.1 | 90.3 | 85.2 | 89.5 | 76.6 |
| Paddy's Run 11&12 | -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 | 0.0 | 0.0 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 11.5 | 32.2 | 23.6 | 14.7 | 10.3 | 8.1 | 14.6 | 11.1 | 13.5 | 13.1 | 14.4 | 12.2 | 16.1 | 8.5 | 4.1 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 71.1 | 67.3 | 87.0 | 72.6 | 70.6 | 66.4 | 71.2 | 66.3 | 70.8 | 60.8 | 71.1 | 66.8 | 72.4 | 65.0 | 65.3 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 21.4 | 21.3 | 18.6 | 12.0 | 11.3 | 8.1 | 12.0 | 9.3 | 11.3 | 10.4 | 11.9 | 10.1 | 13.2 | 6.6 | 3.4 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 15.1 | 22.1 | 14.8 | 8.7 | 7.2 | 8.5 | 8.8 | 6.9 | 8.5 | 7.8 | 9.1 | 7.7 | 10.0 | 4.8 | 2.6 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 13.7 | 15.0 | 11.5 | 6.2 | 6.2 | 5.8 | 6.4 | 5.1 | 6.3 | 5.8 | 6.8 | 5.8 | 7.6 | 3.3 | 1.9 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 10.5 | 14.1 | 8.7 | 4.4 | 4.4 | 4.5 | 3.7 | 3.7 | 4.6 | 3.9 | 5.0 | 4.4 | 5.7 | 2.3 | 1.4 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 8.1 | 10.9 | 6.3 | 3.1 | 3.1 | 3.2 | 3.3 | 2.7 | 3.3 | 3.4 | 3.7 | 3.3 | 4.2 | 1.6 | 1.0 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 6.2 | 8.1 | 4.8 | 2.2 | 2.1 | 2.2 | 2.7 | 2.0 | 2.3 | 2.5 | 2.7 | 2.4 | 3.1 | 1.0 | 0.7 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 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 | 0.0 | 0.0 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 45.8 | 84.2 |

**Sce[illegible] Low Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. [illegible]n 1 | 40.8 | 40.0 | 22.3 | 5.4 | 8.8 | 26.4 | 29.[illegible] | [illegible]2.0 | 14.9 | 8.3 | 8.1 | 9.0 | 9.7 | 9.1 | 9.4 | 11.2 | 9.2 | 10.0 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 6.7 | 11.5 | 21.7 | 25.7 | 20.7 | 13.5 | 9.3 | 7.8 | 8.0 | 9.3 | 8.9 | 8.9 | 9.9 | 9.9 | 9.4 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 1.3 | 2.9 | 13.3 | 15.1 | 10.7 | 7.7 | 5.2 | 4.2 | 4.6 | 4.9 | 4.5 | 4.9 | 5.6 | 5.5 | 5.3 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 2.9 | 1.4 | 2.0 | 1.2 | 1.1 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 43.4 | 6.0 | 4.2 | 2.2 | 2.0 | 0.8 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.8 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 46.1 | 8.0 | 5.5 | 2.5 | 2.7 | 1.1 | 0.7 | 0.7 | 0.7 | 0.9 | 0.8 | 0.9 | 1.1 | 1.0 | 1.0 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 1.7 | 1.0 | 1.7 | 1.0 | 0.9 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 2.7 | 1.7 | 1.5 | 0.8 | 0.7 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 2.1 | 1.3 | 1.2 | 0.6 | 0.6 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 1.4 | 0.8 | 1.4 | 0.8 | 0.8 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 95.1 | 91.1 | 91.2 | 95.1 | 95.1 | 95.1 | 89.2 | 95.1 | 99.5 | 95.1 | 83.3 | 95.1 | 99.5 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 84.5 | 74.1 | 73.9 | 79.4 | 74.9 | 64.4 | 52.5 | 60.2 | 60.8 | 60.9 | 58.8 | 61.1 | 68.4 | 54.6 | 58.8 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 79.3 | 71.0 | 76.5 | 65.8 | 72.8 | 67.3 | 64.6 | 64.0 | 65.3 | 64.9 | 58.3 | 66.3 | 70.7 | 67.5 | 64.9 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 58.7 | 53.2 | 52.1 | 52.9 | 49.3 | 39.3 | 29.7 | 29.1 | 22.4 | 21.6 | 25.1 | 24.8 | 34.6 | 26.5 | 25.7 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 72.9 | 68.5 | 67.8 | 68.7 | 63.5 | 49.1 | 47.0 | 42.4 | 39.3 | 41.1 | 43.3 | 40.2 | 46.8 | 45.7 | 33.7 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 79.7 | 79.5 | 83.1 | 79.9 | 88.7 | 75.4 | 86.7 | 81.5 | 87.3 | 81.3 | 86.5 | 81.6 | 88.3 | 75.3 | 86.7 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 72.6 | 86.4 | 79.3 | 87.9 | 76.7 | 87.5 | 82.0 | 87.1 | 82.6 | 87.2 | 82.5 | 87.0 | 76.1 | 87.4 | 82.6 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 63.7 | 78.3 | 81.3 | 72.7 | 86.7 | 81.0 | 83.4 | 79.3 | 82.8 | 77.5 | 82.3 | 71.5 | 83.8 | 77.7 | 82.2 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 70.2 | 88.8 | 82.7 | 89.7 | 85.1 | 90.5 | 77.7 | 90.3 | 84.8 | 89.8 | 84.6 | 89.3 | 85.1 | 89.3 | 77.0 |
| Paddy's Run 11&12 | -0.1 | 0.2 | -0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 16.6 | 40.8 | 30.7 | 21.4 | 14.7 | 4.1 | 6.1 | 4.9 | 5.8 | 5.7 | 6.2 | 5.5 | 7.0 | 6.4 | 6.5 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 72.2 | 68.0 | 87.4 | 74.2 | 72.9 | 66.0 | 67.9 | 64.1 | 66.7 | 57.2 | 67.1 | 62.4 | 69.5 | 63.5 | 67.1 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 28.6 | 27.6 | 25.0 | 18.1 | 16.9 | 5.5 | 5.0 | 4.2 | 4.8 | 4.5 | 5.2 | 4.6 | 5.8 | 5.3 | 5.5 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 20.6 | 29.4 | 20.3 | 13.6 | 11.1 | 7.9 | 3.6 | 3.1 | 3.5 | 3.4 | 3.9 | 3.5 | 4.4 | 4.1 | 4.2 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 19.2 | 20.4 | 16.3 | 10.1 | 10.0 | 5.5 | 2.6 | 2.3 | 2.6 | 2.6 | 2.9 | 2.7 | 3.3 | 3.1 | 3.2 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 15.1 | 19.7 | 12.9 | 7.5 | 7.4 | 3.9 | 1.7 | 1.7 | 1.9 | 1.8 | 2.2 | 2.0 | 2.5 | 2.3 | 2.4 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 11.8 | 15.8 | 9.6 | 5.4 | 5.4 | 2.6 | 1.4 | 1.3 | 1.4 | 1.5 | 1.6 | 1.5 | 1.8 | 1.7 | 1.8 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 9.2 | 12.1 | 7.7 | 3.9 | 3.8 | 1.7 | 1.0 | 0.9 | 1.0 | 1.1 | 1.2 | 1.1 | 1.3 | 1.3 | 1.4 |
| Zorn 1 | 0.2 | 0.1 | 0.9 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 40.2 | 70.5 | 65.8 | 77.9 | 79.5 | 80.2 | 81.6 | 66.6 | 82.4 | 88.9 |

**Sce[illegible]Low Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W.[illegible]n 1 | 40.8 | 40.0 | 22.3 | 2.1 | 3.5 | 15.0 | 15.[illegible] | [illegible]1.0 | 12.4 | 12.1 | 11.8 | 13.5 | 15.0 | 13.0 | 13.8 | 16.9 | 12.9 | 14.2 |
| E.W. Brown 2 | 60.2 | 51.8 | 42.7 | 2.9 | 5.7 | 12.6 | 14.3 | 11.1 | 11.9 | 14.1 | 11.6 | 11.9 | 14.3 | 13.2 | 13.3 | 14.9 | 14.6 | 13.5 |
| E.W. Brown 3 | 44.5 | 42.1 | 33.5 | 0.4 | 0.9 | 7.2 | 7.6 | 5.3 | 6.4 | 7.9 | 6.1 | 6.8 | 7.4 | 6.4 | 7.2 | 8.4 | 8.1 | 7.5 |
| E.W. Brown 5 | 0.3 | 3.5 | 10.8 | 1.0 | 0.4 | 0.5 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 |
| E.W. Brown 6 | 3.9 | 13.7 | 16.2 | 25.1 | 2.0 | 1.2 | 0.5 | 0.5 | 0.5 | 0.6 | 0.5 | 0.6 | 0.6 | 0.7 | 0.7 | 0.9 | 0.8 | 0.9 |
| E.W. Brown 7 | 3.4 | 16.3 | 12.5 | 28.3 | 3.0 | 1.8 | 0.7 | 0.7 | 0.7 | 0.9 | 0.7 | 0.9 | 1.1 | 1.0 | 1.0 | 1.5 | 1.2 | 1.2 |
| E.W. Brown 8 | 0.3 | 2.2 | 7.3 | 0.4 | 0.2 | 0.4 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 |
| E.W. Brown 9 | 0.5 | 1.6 | 8.4 | 0.8 | 0.4 | 0.3 | 0.1 | 0.1 | 0.1 | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.2 | 0.3 |
| E.W. Brown 10 | 0.1 | 1.8 | 7.8 | 0.6 | 0.3 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| E.W. Brown 11 | 0.1 | 2.2 | 5.4 | 0.3 | 0.2 | 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 |
| Cane Run 4 | 51.3 | 56.7 | 40.1 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 58.7 | 66.1 | 45.5 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 47.3 | 36.2 | 25.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 19.7 | 94.1 | 95.1 | 95.1 | 90.9 | 91.1 | 95.0 | 95.0 | 95.0 | 89.2 | 95.0 | 99.5 | 95.1 | 83.0 | 95.1 | 99.5 |
| Cane Run 11 | 0.1 | -0.1 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |
| Ghent 1 | 79.5 | 77.5 | 60.9 | 83.4 | 66.8 | 65.1 | 71.6 | 64.4 | 63.1 | 53.7 | 63.0 | 66.4 | 67.7 | 66.2 | 69.1 | 71.0 | 61.3 | 69.5 |
| Ghent 2 | 81.0 | 77.7 | 58.8 | 77.7 | 67.8 | 73.2 | 61.6 | 67.2 | 66.7 | 68.7 | 66.8 | 69.0 | 68.8 | 61.8 | 70.9 | 72.4 | 71.9 | 69.8 |
| Ghent 3 | 76.9 | 71.7 | 71.1 | 43.5 | 37.5 | 38.0 | 36.3 | 32.8 | 33.6 | 35.6 | 32.1 | 32.2 | 30.8 | 36.0 | 35.8 | 40.4 | 38.4 | 36.3 |
| Ghent 4 | 73.3 | 70.9 | 80.3 | 61.7 | 52.8 | 53.6 | 52.3 | 45.9 | 43.5 | 51.6 | 46.7 | 47.5 | 50.2 | 52.0 | 48.8 | 46.7 | 55.3 | 49.6 |
| Green River 3 | 52.2 | 59.3 | 49.9 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 80.1 | 82.8 | 71.3 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 0.2 | 0.4 | 1.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Mill Creek 1 | 55.3 | 74.0 | 56.3 | 78.4 | 77.8 | 80.8 | 77.7 | 87.5 | 75.1 | 87.2 | 81.6 | 88.0 | 82.3 | 87.3 | 82.4 | 88.6 | 75.7 | 87.8 |
| Mill Creek 2 | 72.0 | 66.6 | 55.6 | 70.4 | 84.8 | 77.1 | 86.3 | 75.9 | 87.1 | 82.6 | 87.6 | 83.0 | 87.9 | 83.0 | 87.7 | 76.4 | 88.0 | 83.2 |
| Mill Creek 3 | 64.6 | 78.0 | 63.6 | 59.2 | 77.0 | 78.4 | 70.7 | 84.7 | 80.2 | 84.2 | 79.3 | 84.0 | 78.7 | 83.8 | 72.7 | 84.4 | 79.1 | 83.7 |
| Mill Creek 4 | 64.8 | 55.6 | 67.8 | 62.4 | 86.8 | 79.9 | 88.4 | 84.7 | 89.9 | 77.6 | 89.8 | 84.9 | 90.0 | 84.9 | 90.0 | 85.1 | 90.0 | 77.9 |
| Paddy's Run 11&12 | -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 | 0.1 | 0.1 | 0.1 |
| Paddy's Run 13 | 2.3 | 8.1 | 14.1 | 7.5 | 24.3 | 17.4 | 9.3 | 6.8 | 5.4 | 9.5 | 7.1 | 8.8 | 8.6 | 9.5 | 8.0 | 10.8 | 9.5 | 9.4 |
| Trimble County 1 (75%) | 77.6 | 80.0 | 64.4 | 69.9 | 66.5 | 86.5 | 71.0 | 68.4 | 64.1 | 68.8 | 64.1 | 68.6 | 58.9 | 68.9 | 64.6 | 70.2 | 65.4 | 69.3 |
| Trimble County 2 (75%) | 65.3 | 58.8 | 84.2 | 82.9 | 86.4 | 75.7 | 82.8 | 82.9 | 86.4 | 82.8 | 86.4 | 82.9 | 82.8 | 75.7 | 82.8 | 82.9 | 82.8 | 82.8 |
| Trimble County 5 | 4.8 | 9.5 | 14.5 | 15.3 | 15.7 | 13.3 | 7.4 | 7.0 | 5.1 | 7.5 | 5.8 | 7.2 | 6.6 | 7.7 | 6.5 | 8.6 | 7.7 | 7.7 |
| Trimble County 6 | 6.5 | 10.4 | 13.8 | 10.6 | 15.8 | 10.2 | 5.1 | 4.4 | 5.1 | 5.3 | 4.2 | 5.2 | 4.8 | 5.6 | 4.8 | 6.4 | 5.7 | 5.8 |
| Trimble County 7 | 5.2 | 7.7 | 16.4 | 9.3 | 10.4 | 7.6 | 3.5 | 3.6 | 3.3 | 3.7 | 3.0 | 3.7 | 3.5 | 4.1 | 3.5 | 4.7 | 4.2 | 4.3 |
| Trimble County 8 | 2.0 | 2.9 | 5.0 | 7.0 | 9.4 | 5.5 | 2.4 | 2.4 | 2.5 | 2.1 | 2.1 | 2.6 | 2.3 | 2.9 | 2.6 | 3.4 | 3.0 | 3.1 |
| Trimble County 9 | 6.2 | 9.0 | 17.5 | 5.2 | 7.1 | 3.8 | 1.6 | 1.6 | 1.7 | 1.8 | 1.5 | 1.8 | 1.9 | 2.1 | 1.9 | 2.4 | 2.2 | 2.3 |
| Trimble County 10 | 1.9 | 3.7 | 4.6 | 3.8 | 5.1 | 2.7 | 1.1 | 1.1 | 1.1 | 1.4 | 1.1 | 1.3 | 1.3 | 1.4 | 1.3 | 1.7 | 1.6 | 1.7 |
| Zorn 1 | 0.2 | 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 | 0.1 | 0.1 | 0.1 |
| Dix Dam 1-3 | 50.7 | 27.5 | 35.5 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 | 25.7 |
| Ohio Falls 1-8 | 40.9 | 57.5 | 52.1 | 44.6 | 46.9 | 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 |
| Brown Solar | NA | NA | NA | 18.8 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 | 17.4 | 17.3 | 17.4 | 17.4 |

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

(2) Haefling 1-2 actuals include Haefling 3

**Kentucky Utilities Company and Louisville Gas and Electric Company**
**UNIT PERFORMANCE DATA (1)**



**Average Heat Rate (Btu/kWh)**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Unit Name** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **Scenario: Mid Gas - Base Load** | | | | | | | | | | | | | | | | | | |
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 10,981 | 10,763 | 10,746 | 10,700 | 10,681 | 10,827 | 10,804 | 10,787 | 10,628 | 10,562 | 10,579 | 10,576 | 10,566 | 10,558 | 10,568 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,622 | 10,534 | 10,469 | 10,511 | 10,504 | 10,553 | 10,528 | 10,531 | 10,417 | 10,406 | 10,410 | 10,411 | 10,406 | 10,396 | 10,403 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,599 | 11,593 | 11,774 | 11,746 | 11,659 | 11,390 | 11,352 | 11,469 | 11,450 | 11,460 | 11,362 | 11,339 | 11,312 | 11,264 | 11,243 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,494 | 12,744 | 13,092 | 13,476 | 13,995 | 14,070 | 14,089 | 13,974 | 13,998 | 13,952 | 13,926 | 13,871 | 13,883 | 14,168 | 14,042 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,877 | 11,045 | 11,230 | 11,270 | 11,383 | 11,582 | 11,572 | 11,562 | 11,559 | 11,547 | 11,543 | 11,538 | 11,518 | 11,600 | 11,591 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,843 | 10,996 | 11,171 | 11,194 | 11,363 | 11,541 | 11,506 | 11,537 | 11,626 | 11,632 | 11,573 | 11,599 | 11,620 | 11,595 | 11,627 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,716 | 12,975 | 13,386 | 14,310 | 14,704 | 14,653 | 14,652 | 14,630 | 14,578 | 14,559 | 14,509 | 14,481 | 14,397 | 14,765 | 14,708 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,693 | 13,195 | 13,558 | 13,906 | 14,228 | 14,156 | 14,310 | 13,930 | 14,140 | 14,057 | 14,092 | 13,943 | 14,088 | 14,508 | 14,039 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,691 | 13,087 | 13,328 | 13,585 | 13,684 | 13,647 | 13,781 | 13,475 | 13,621 | 13,544 | 13,590 | 13,463 | 13,594 | 13,928 | 13,505 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,708 | 12,861 | 13,322 | 13,917 | 14,325 | 14,213 | 14,188 | 14,187 | 14,129 | 14,113 | 14,133 | 14,118 | 14,037 | 14,339 | 14,304 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6,980 | 6,831 | 6,831 | 6,848 | 6,884 | 6,963 | 7,084 | 7,090 | 7,113 | 7,132 | 7,131 | 7,175 | 7,214 | 7,188 | 7,241 | 7,301 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,759 | 10,788 | 10,824 | 10,799 | 10,794 | 10,788 | 10,785 | 10,788 | 10,788 | 10,785 | 10,784 | 10,783 | 10,787 | 10,783 | 10,781 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,516 | 10,504 | 10,499 | 10,503 | 10,498 | 10,508 | 10,509 | 10,517 | 10,518 | 10,522 | 10,519 | 10,520 | 10,522 | 10,523 | 10,521 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,124 | 11,149 | 11,127 | 11,144 | 11,152 | 11,130 | 11,113 | 11,116 | 11,113 | 11,101 | 11,101 | 11,105 | 11,103 | 11,100 | 11,098 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,942 | 10,983 | 10,973 | 10,941 | 10,943 | 10,932 | 10,916 | 10,927 | 10,927 | 10,922 | 10,918 | 10,917 | 10,921 | 10,915 | 10,912 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,310 | 10,335 | 10,319 | 10,335 | 10,379 | 10,381 | 10,381 | 10,380 | 10,383 | 10,382 | 10,383 | 10,381 | 10,382 | 10,380 | 10,383 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,530 | 10,551 | 10,538 | 10,561 | 10,568 | 10,567 | 10,569 | 10,568 | 10,568 | 10,568 | 10,569 | 10,568 | 10,568 | 10,567 | 10,569 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,472 | 10,499 | 10,466 | 10,481 | 10,512 | 10,519 | 10,514 | 10,515 | 10,511 | 10,513 | 10,514 | 10,515 | 10,514 | 10,515 | 10,512 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,642 | 10,642 | 10,656 | 10,651 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,685 | 10,704 | 10,872 | 10,876 | 11,517 | 13,035 | 13,179 | 13,164 | 13,165 | 13,146 | 13,147 | 13,107 | 13,115 | 13,254 | 13,218 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,430 | 10,480 | 10,556 | 10,473 | 10,432 | 10,451 | 10,457 | 10,474 | 10,476 | 10,487 | 10,485 | 10,485 | 10,485 | 10,493 | 10,487 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,976 | 10,910 | 11,072 | 11,160 | 11,342 | 11,618 | 11,768 | 12,046 | 12,153 | 12,235 | 12,345 | 12,371 | 12,379 | 12,373 | 12,094 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,987 | 10,950 | 11,109 | 11,192 | 11,366 | 11,685 | 11,709 | 11,972 | 12,054 | 12,113 | 12,252 | 12,245 | 12,251 | 12,267 | 12,035 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 11,008 | 10,966 | 11,144 | 11,222 | 11,326 | 11,690 | 11,688 | 11,929 | 11,976 | 11,958 | 12,108 | 12,105 | 12,114 | 12,164 | 12,029 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 11,022 | 10,992 | 11,179 | 11,250 | 11,337 | 11,665 | 11,610 | 11,868 | 11,885 | 11,842 | 11,879 | 11,881 | 11,904 | 12,017 | 11,980 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,034 | 11,009 | 11,208 | 11,276 | 11,346 | 11,647 | 11,655 | 11,824 | 11,851 | 11,832 | 11,814 | 11,797 | 11,794 | 11,920 | 11,895 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,032 | 11,025 | 11,241 | 11,299 | 11,353 | 11,627 | 11,651 | 11,727 | 11,733 | 11,727 | 11,691 | 11,680 | 11,669 | 11,790 | 11,769 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 7,089 | 7,173 |

**Scenario: Mid Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 10,916 | 10,724 | 10,695 | 10,657 | 10,646 | 10,860 | 10,791 | 10,712 | 10,580 | 10,519 | 10,538 | 10,535 | 10,529 | 10,524 | 10,529 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,592 | 10,508 | 10,446 | 10,482 | 10,478 | 10,575 | 10,523 | 10,487 | 10,390 | 10,376 | 10,380 | 10,382 | 10,378 | 10,369 | 10,375 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,581 | 11,580 | 11,736 | 11,700 | 11,606 | 11,458 | 11,357 | 11,440 | 11,360 | 11,365 | 11,285 | 11,263 | 11,237 | 11,196 | 11,183 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,465 | 12,690 | 13,036 | 13,381 | 13,859 | 14,246 | 14,083 | 14,021 | 14,001 | 13,978 | 13,952 | 13,915 | 13,908 | 13,911 | 13,883 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,842 | 11,015 | 11,186 | 11,230 | 11,345 | 11,604 | 11,593 | 11,581 | 11,574 | 11,567 | 11,569 | 11,562 | 11,546 | 11,555 | 11,540 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,816 | 10,974 | 11,135 | 11,166 | 11,322 | 11,561 | 11,539 | 11,563 | 11,613 | 11,623 | 11,603 | 11,616 | 11,630 | 11,601 | 11,575 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,692 | 12,919 | 13,299 | 14,113 | 14,473 | 14,706 | 14,730 | 14,711 | 14,658 | 14,639 | 14,594 | 14,563 | 14,496 | 14,544 | 14,487 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,669 | 13,120 | 13,492 | 13,831 | 14,155 | 14,705 | 14,084 | 13,898 | 13,992 | 13,950 | 13,977 | 13,888 | 13,979 | 13,926 | 13,922 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,667 | 13,025 | 13,279 | 13,529 | 13,655 | 14,125 | 13,583 | 13,449 | 13,482 | 13,448 | 13,477 | 13,403 | 13,482 | 13,437 | 13,439 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,686 | 12,819 | 13,235 | 13,764 | 14,127 | 14,246 | 14,257 | 14,248 | 14,190 | 14,176 | 14,208 | 14,186 | 14,125 | 14,170 | 14,121 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,831 | 6,831 | 6,845 | 6,877 | 6,939 | 7,042 | 7,048 | 7,078 | 7,096 | 7,107 | 7,143 | 7,189 | 7,155 | 7,197 | 7,250 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,758 | 10,777 | 10,808 | 10,790 | 10,787 | 10,782 | 10,780 | 10,783 | 10,782 | 10,781 | 10,779 | 10,781 | 10,780 | 10,781 | 10,780 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,523 | 10,507 | 10,506 | 10,508 | 10,503 | 10,513 | 10,515 | 10,522 | 10,524 | 10,528 | 10,525 | 10,526 | 10,528 | 10,529 | 10,527 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,110 | 11,129 | 11,113 | 11,121 | 11,133 | 11,110 | 11,097 | 11,097 | 11,097 | 11,086 | 11,086 | 11,089 | 11,088 | 11,087 | 11,085 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,924 | 10,953 | 10,952 | 10,925 | 10,925 | 10,921 | 10,906 | 10,913 | 10,914 | 10,910 | 10,907 | 10,905 | 10,911 | 10,905 | 10,901 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,319 | 10,344 | 10,330 | 10,345 | 10,381 | 10,383 | 10,383 | 10,382 | 10,384 | 10,383 | 10,384 | 10,383 | 10,383 | 10,381 | 10,384 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,534 | 10,555 | 10,543 | 10,563 | 10,568 | 10,568 | 10,569 | 10,569 | 10,569 | 10,568 | 10,569 | 10,568 | 10,569 | 10,568 | 10,569 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,476 | 10,504 | 10,474 | 10,490 | 10,517 | 10,522 | 10,519 | 10,520 | 10,517 | 10,518 | 10,518 | 10,519 | 10,519 | 10,519 | 10,517 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,641 | 10,644 | 10,654 | 10,651 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,649 | 10,663 | 10,804 | 10,822 | 11,505 | 13,094 | 13,222 | 13,211 | 13,202 | 13,192 | 13,192 | 13,157 | 13,168 | 13,159 | 13,131 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,443 | 10,494 | 10,560 | 10,490 | 10,449 | 10,471 | 10,476 | 10,494 | 10,496 | 10,507 | 10,504 | 10,504 | 10,505 | 10,512 | 10,506 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,939 | 10,875 | 11,020 | 11,105 | 11,290 | 11,666 | 11,788 | 12,080 | 12,096 | 12,072 | 12,057 | 12,043 | 12,034 | 12,034 | 12,012 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,951 | 10,911 | 11,054 | 11,137 | 11,322 | 11,716 | 11,735 | 12,034 | 12,029 | 12,010 | 12,010 | 11,980 | 11,982 | 11,980 | 11,955 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 10,973 | 10,927 | 11,087 | 11,167 | 11,280 | 11,732 | 11,708 | 11,979 | 12,026 | 12,006 | 11,992 | 11,972 | 11,966 | 11,967 | 11,942 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 10,988 | 10,953 | 11,120 | 11,195 | 11,290 | 11,695 | 11,645 | 11,914 | 11,963 | 11,947 | 11,934 | 11,921 | 11,913 | 11,912 | 11,891 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,000 | 10,972 | 11,147 | 11,221 | 11,298 | 11,682 | 11,672 | 11,865 | 11,883 | 11,867 | 11,860 | 11,840 | 11,834 | 11,834 | 11,809 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,001 | 10,988 | 11,180 | 11,244 | 11,304 | 11,650 | 11,666 | 11,763 | 11,763 | 11,755 | 11,730 | 11,719 | 11,707 | 11,711 | 11,689 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 6,894 | 6,983 | 7,050 | 7,162 | 7,146 | 7,140 | 7,123 | 7,117 | 7,116 | 7,113 |

**Scenario: Mid Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 11,049 | 10,802 | 10,801 | 10,743 | 10,717 | 10,887 | 10,864 | 10,874 | 10,677 | 10,611 | 10,624 | 10,619 | 10,605 | 10,593 | 10,609 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,651 | 10,559 | 10,493 | 10,540 | 10,529 | 10,589 | 10,568 | 10,579 | 10,447 | 10,441 | 10,444 | 10,442 | 10,437 | 10,427 | 10,433 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,616 | 11,605 | 11,809 | 11,786 | 11,708 | 11,437 | 11,413 | 11,528 | 11,517 | 11,541 | 11,432 | 11,406 | 11,382 | 11,334 | 11,305 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,524 | 12,801 | 13,147 | 13,570 | 14,128 | 14,226 | 14,240 | 14,141 | 14,152 | 14,111 | 14,081 | 14,032 | 14,041 | 14,035 | 14,002 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,913 | 11,075 | 11,275 | 11,311 | 11,419 | 11,635 | 11,630 | 11,614 | 11,612 | 11,601 | 11,599 | 11,592 | 11,575 | 11,586 | 11,566 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,871 | 11,018 | 11,205 | 11,222 | 11,403 | 11,589 | 11,557 | 11,589 | 11,675 | 11,686 | 11,631 | 11,655 | 11,682 | 11,637 | 11,600 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,739 | 13,033 | 13,479 | 14,509 | 14,935 | 14,895 | 14,894 | 14,867 | 14,817 | 14,794 | 14,743 | 14,708 | 14,631 | 14,690 | 14,622 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,716 | 13,271 | 13,623 | 13,982 | 14,288 | 14,232 | 14,384 | 14,026 | 14,225 | 14,142 | 14,175 | 14,035 | 14,196 | 14,095 | 14,082 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,716 | 13,152 | 13,377 | 13,643 | 13,702 | 13,678 | 13,809 | 13,529 | 13,654 | 13,574 | 13,621 | 13,497 | 13,648 | 13,557 | 13,552 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,733 | 12,904 | 13,414 | 14,070 | 14,518 | 14,407 | 14,386 | 14,377 | 14,323 | 14,301 | 14,331 | 14,307 | 14,235 | 14,292 | 14,233 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,831 | 6,831 | 6,852 | 6,889 | 6,990 | 7,128 | 7,139 | 7,149 | 7,180 | 7,159 | 7,217 | 7,247 | 7,229 | 7,292 | 7,348 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,757 | 10,810 | 10,843 | 10,811 | 10,804 | 10,798 | 10,793 | 10,798 | 10,797 | 10,793 | 10,793 | 10,790 | 10,794 | 10,790 | 10,788 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,508 | 10,503 | 10,496 | 10,500 | 10,493 | 10,501 | 10,502 | 10,510 | 10,511 | 10,515 | 10,512 | 10,513 | 10,514 | 10,516 | 10,514 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,139 | 11,170 | 11,144 | 11,171 | 11,172 | 11,155 | 11,134 | 11,138 | 11,133 | 11,120 | 11,119 | 11,125 | 11,123 | 11,117 | 11,115 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,966 | 11,023 | 10,998 | 10,964 | 10,969 | 10,951 | 10,933 | 10,947 | 10,948 | 10,941 | 10,935 | 10,935 | 10,938 | 10,931 | 10,932 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,302 | 10,327 | 10,308 | 10,325 | 10,377 | 10,380 | 10,380 | 10,378 | 10,382 | 10,380 | 10,381 | 10,379 | 10,381 | 10,378 | 10,382 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,526 | 10,547 | 10,532 | 10,558 | 10,568 | 10,566 | 10,568 | 10,568 | 10,568 | 10,567 | 10,568 | 10,567 | 10,568 | 10,566 | 10,568 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,470 | 10,494 | 10,458 | 10,473 | 10,507 | 10,514 | 10,508 | 10,510 | 10,505 | 10,507 | 10,508 | 10,510 | 10,508 | 10,509 | 10,506 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,644 | 10,641 | 10,658 | 10,652 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,724 | 10,746 | 10,947 | 10,930 | 11,520 | 13,148 | 13,264 | 13,247 | 13,250 | 13,234 | 13,235 | 13,199 | 13,206 | 13,201 | 13,183 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,418 | 10,467 | 10,552 | 10,455 | 10,415 | 10,430 | 10,437 | 10,451 | 10,454 | 10,465 | 10,464 | 10,463 | 10,464 | 10,472 | 10,465 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 11,014 | 10,946 | 11,129 | 11,219 | 11,393 | 11,676 | 11,837 | 12,131 | 12,250 | 12,358 | 12,478 | 12,507 | 12,515 | 12,517 | 12,467 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 11,024 | 10,993 | 11,169 | 11,251 | 11,411 | 11,748 | 11,774 | 12,061 | 12,148 | 12,229 | 12,383 | 12,380 | 12,384 | 12,387 | 12,339 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 11,045 | 11,008 | 11,207 | 11,282 | 11,376 | 11,753 | 11,755 | 12,023 | 12,074 | 12,061 | 12,234 | 12,233 | 12,243 | 12,258 | 12,251 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 11,059 | 11,033 | 11,243 | 11,310 | 11,388 | 11,731 | 11,676 | 11,962 | 11,980 | 11,944 | 11,980 | 11,984 | 12,008 | 11,976 | 11,951 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,070 | 11,050 | 11,272 | 11,335 | 11,397 | 11,715 | 11,728 | 11,917 | 11,945 | 11,927 | 11,909 | 11,892 | 11,890 | 11,885 | 11,856 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,067 | 11,064 | 11,305 | 11,358 | 11,403 | 11,695 | 11,726 | 11,811 | 11,820 | 11,812 | 11,777 | 11,765 | 11,754 | 11,758 | 11,731 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |

**Scenario: High Gas - Base Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 10,659 | 10,656 | 10,656 | 10,833 | 10,682 | 10,581 | 10,556 | 10,586 | 10,585 | 10,562 | 10,579 | 10,576 | 10,566 | 10,558 | 10,568 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,481 | 10,479 | 10,458 | 10,547 | 10,480 | 10,425 | 10,403 | 10,422 | 10,412 | 10,403 | 10,405 | 10,411 | 10,406 | 10,397 | 10,403 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,581 | 11,533 | 11,471 | 11,376 | 11,425 | 11,335 | 11,241 | 11,291 | 11,259 | 11,273 | 11,227 | 11,263 | 11,237 | 11,225 | 11,238 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,791 | 13,171 | 13,975 | 14,142 | 14,113 | 14,077 | 14,088 | 13,974 | 13,998 | 13,952 | 13,926 | 13,871 | 13,883 | 13,509 | 13,426 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,946 | 11,117 | 11,492 | 11,585 | 11,595 | 11,593 | 11,572 | 11,562 | 11,559 | 11,547 | 11,543 | 11,538 | 11,518 | 11,559 | 11,542 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,921 | 11,086 | 11,359 | 11,535 | 11,570 | 11,570 | 11,538 | 11,569 | 11,625 | 11,623 | 11,568 | 11,599 | 11,620 | 11,603 | 11,569 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 13,011 | 13,208 | 14,511 | 14,749 | 14,716 | 14,650 | 14,651 | 14,629 | 14,578 | 14,559 | 14,509 | 14,481 | 14,397 | 13,896 | 13,826 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 13,448 | 14,126 | 14,394 | 14,217 | 14,198 | 14,153 | 14,308 | 13,929 | 14,140 | 14,057 | 14,092 | 13,943 | 14,088 | 13,521 | 13,359 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 13,261 | 13,860 | 13,900 | 13,696 | 13,677 | 13,641 | 13,779 | 13,474 | 13,621 | 13,544 | 13,590 | 13,463 | 13,594 | 13,258 | 13,111 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,889 | 12,971 | 14,102 | 14,291 | 14,250 | 14,209 | 14,187 | 14,186 | 14,129 | 14,113 | 14,133 | 14,118 | 14,037 | 13,538 | 13,492 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,859 | 6,901 | 7,058 | 7,102 | 7,156 | 7,245 | 7,336 | 7,336 | 7,317 | 7,336 | 7,307 | 7,323 | 7,294 | 7,303 | 7,306 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,760 | 10,765 | 10,783 | 10,781 | 10,791 | 10,787 | 10,785 | 10,788 | 10,788 | 10,785 | 10,784 | 10,783 | 10,787 | 10,783 | 10,782 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,521 | 10,501 | 10,504 | 10,504 | 10,518 | 10,521 | 10,520 | 10,518 | 10,518 | 10,522 | 10,519 | 10,520 | 10,522 | 10,523 | 10,521 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,113 | 11,132 | 11,095 | 11,101 | 11,109 | 11,109 | 11,104 | 11,115 | 11,111 | 11,100 | 11,100 | 11,104 | 11,102 | 11,100 | 11,098 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,925 | 10,922 | 10,919 | 10,912 | 10,930 | 10,932 | 10,916 | 10,927 | 10,927 | 10,922 | 10,918 | 10,917 | 10,921 | 10,915 | 10,912 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,315 | 10,345 | 10,332 | 10,359 | 10,382 | 10,381 | 10,382 | 10,380 | 10,383 | 10,382 | 10,383 | 10,381 | 10,382 | 10,380 | 10,383 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,534 | 10,557 | 10,545 | 10,566 | 10,568 | 10,567 | 10,569 | 10,568 | 10,568 | 10,568 | 10,569 | 10,568 | 10,568 | 10,567 | 10,569 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,474 | 10,504 | 10,481 | 10,499 | 10,516 | 10,519 | 10,515 | 10,515 | 10,511 | 10,513 | 10,514 | 10,515 | 10,514 | 10,515 | 10,512 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,636 | 10,642 | 10,652 | 10,651 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,897 | 10,791 | 12,063 | 13,209 | 13,192 | 13,123 | 13,180 | 13,167 | 13,166 | 13,154 | 13,149 | 13,114 | 13,123 | 13,133 | 13,102 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,445 | 10,485 | 10,565 | 10,503 | 10,472 | 10,483 | 10,486 | 10,479 | 10,477 | 10,487 | 10,485 | 10,484 | 10,485 | 10,493 | 10,487 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 11,026 | 11,125 | 11,346 | 11,692 | 12,282 | 12,423 | 12,473 | 12,459 | 12,522 | 12,440 | 12,408 | 12,373 | 12,455 | 12,373 | 12,335 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 11,027 | 11,139 | 11,378 | 11,680 | 12,153 | 12,506 | 12,342 | 12,322 | 12,368 | 12,297 | 12,286 | 12,236 | 12,313 | 12,247 | 12,208 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 11,045 | 11,158 | 11,413 | 11,669 | 12,116 | 12,373 | 12,178 | 12,145 | 12,268 | 12,186 | 12,189 | 12,159 | 12,192 | 12,147 | 12,117 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 11,056 | 11,161 | 11,442 | 11,661 | 11,964 | 12,138 | 11,918 | 11,931 | 12,006 | 11,916 | 11,897 | 11,881 | 11,900 | 11,886 | 11,865 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,061 | 11,168 | 11,441 | 11,646 | 11,910 | 11,994 | 11,878 | 11,830 | 11,861 | 11,844 | 11,817 | 11,797 | 11,794 | 11,795 | 11,768 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,083 | 11,169 | 11,451 | 11,639 | 11,804 | 11,839 | 11,801 | 11,734 | 11,733 | 11,727 | 11,691 | 11,680 | 11,669 | 11,675 | 11,651 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |
| SCCT | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9,940 | 9,940 |

**Scenario: High Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 10,619 | 10,615 | 10,611 | 10,750 | 10,629 | 10,537 | 10,520 | 10,543 | 10,543 | 10,519 | 10,537 | 10,535 | 10,529 | 10,524 | 10,529 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,455 | 10,451 | 10,434 | 10,501 | 10,444 | 10,393 | 10,375 | 10,391 | 10,386 | 10,373 | 10,376 | 10,382 | 10,378 | 10,370 | 10,376 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,554 | 11,491 | 11,408 | 11,314 | 11,358 | 11,262 | 11,173 | 11,230 | 11,202 | 11,203 | 11,173 | 11,202 | 11,179 | 11,162 | 11,178 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,740 | 13,082 | 13,832 | 13,970 | 13,963 | 14,281 | 14,082 | 14,019 | 14,000 | 13,978 | 13,952 | 13,915 | 13,908 | 13,911 | 13,883 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,913 | 11,090 | 11,432 | 11,526 | 11,539 | 11,636 | 11,592 | 11,580 | 11,574 | 11,567 | 11,569 | 11,562 | 11,546 | 11,555 | 11,540 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,895 | 11,062 | 11,318 | 11,479 | 11,517 | 11,617 | 11,565 | 11,577 | 11,613 | 11,623 | 11,603 | 11,616 | 11,630 | 11,601 | 11,575 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,962 | 13,147 | 14,285 | 14,485 | 14,478 | 14,702 | 14,729 | 14,708 | 14,657 | 14,639 | 14,594 | 14,563 | 14,496 | 14,544 | 14,487 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 13,369 | 13,994 | 14,282 | 14,112 | 14,130 | 14,704 | 14,081 | 13,895 | 13,991 | 13,950 | 13,977 | 13,888 | 13,979 | 13,926 | 13,922 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 13,194 | 13,739 | 13,837 | 13,642 | 13,652 | 14,114 | 13,581 | 13,446 | 13,481 | 13,448 | 13,477 | 13,403 | 13,482 | 13,437 | 13,439 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,851 | 12,931 | 13,907 | 14,077 | 14,057 | 14,243 | 14,255 | 14,245 | 14,190 | 14,176 | 14,208 | 14,186 | 14,125 | 14,170 | 14,121 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,855 | 6,888 | 7,019 | 7,051 | 7,109 | 7,211 | 7,279 | 7,294 | 7,255 | 7,286 | 7,251 | 7,279 | 7,244 | 7,251 | 7,258 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,758 | 10,762 | 10,779 | 10,777 | 10,784 | 10,782 | 10,780 | 10,783 | 10,782 | 10,781 | 10,779 | 10,781 | 10,780 | 10,781 | 10,780 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,528 | 10,507 | 10,512 | 10,510 | 10,524 | 10,527 | 10,526 | 10,524 | 10,524 | 10,528 | 10,525 | 10,526 | 10,528 | 10,529 | 10,527 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,099 | 11,114 | 11,082 | 11,086 | 11,093 | 11,092 | 11,088 | 11,097 | 11,095 | 11,085 | 11,086 | 11,089 | 11,088 | 11,086 | 11,085 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,914 | 10,909 | 10,911 | 10,902 | 10,914 | 10,921 | 10,906 | 10,913 | 10,914 | 10,910 | 10,907 | 10,905 | 10,911 | 10,905 | 10,901 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,324 | 10,352 | 10,342 | 10,366 | 10,383 | 10,383 | 10,383 | 10,382 | 10,384 | 10,383 | 10,384 | 10,383 | 10,383 | 10,381 | 10,384 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,538 | 10,560 | 10,550 | 10,568 | 10,569 | 10,568 | 10,569 | 10,569 | 10,569 | 10,568 | 10,569 | 10,568 | 10,569 | 10,568 | 10,569 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,480 | 10,509 | 10,489 | 10,506 | 10,520 | 10,522 | 10,520 | 10,520 | 10,517 | 10,518 | 10,518 | 10,519 | 10,518 | 10,519 | 10,517 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,638 | 10,644 | 10,652 | 10,651 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,836 | 10,761 | 11,969 | 13,110 | 13,084 | 13,194 | 13,233 | 13,202 | 13,203 | 13,192 | 13,192 | 13,157 | 13,168 | 13,159 | 13,131 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,461 | 10,498 | 10,567 | 10,518 | 10,492 | 10,503 | 10,505 | 10,500 | 10,497 | 10,507 | 10,504 | 10,504 | 10,505 | 10,511 | 10,506 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9.178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,991 | 11,083 | 11,285 | 11,636 | 12,186 | 12,228 | 12,110 | 12,090 | 12,094 | 12,072 | 12,057 | 12,043 | 12,034 | 12,034 | 12,012 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,993 | 11,096 | 11,313 | 11,620 | 12,059 | 12,499 | 12,049 | 12,024 | 12,029 | 12,010 | 12,010 | 11,980 | 11,982 | 11,980 | 11,955 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 11,013 | 11,116 | 11,344 | 11,605 | 12,022 | 12,442 | 12,037 | 12,016 | 12,024 | 12,006 | 11,992 | 11,972 | 11,966 | 11,967 | 11,942 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 11,024 | 11,119 | 11,369 | 11,596 | 11,873 | 12,298 | 11,968 | 11,967 | 11,971 | 11,947 | 11,934 | 11,921 | 11,913 | 11,912 | 11,891 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,029 | 11,126 | 11,367 | 11,577 | 11,819 | 12,161 | 11,896 | 11,867 | 11,882 | 11,867 | 11,860 | 11,840 | 11,834 | 11,834 | 11,809 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,049 | 11,127 | 11,378 | 11,568 | 11,719 | 11,956 | 11,818 | 11,765 | 11,763 | 11,755 | 11,730 | 11,719 | 11,707 | 11,711 | 11,689 |
| Zorn 1 | 25,887 | 40.436 | 20,388 | 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 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 7,082 | 7,163 | 7,157 | 7,168 | 7,162 | 7,144 | 7,132 | 7,130 | 7,128 | 7,109 |

**Scenario: High Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 10,702 | 10,699 | 10,710 | 10,917 | 10,738 | 10,628 | 10,597 | 10,630 | 10,631 | 10,611 | 10,623 | 10,619 | 10,605 | 10,593 | 10,609 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,509 | 10,506 | 10,483 | 10,592 | 10,517 | 10,460 | 10,434 | 10,454 | 10,440 | 10,436 | 10,437 | 10,442 | 10,436 | 10,428 | 10,433 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,605 | 11,572 | 11,535 | 11,440 | 11,492 | 11,404 | 11,316 | 11,353 | 11,321 | 11,344 | 11,283 | 11,326 | 11,301 | 11,292 | 11,299 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,844 | 13,264 | 14,118 | 14,315 | 14,262 | 14,229 | 14,238 | 14,141 | 14,152 | 14,111 | 14,081 | 14,032 | 14,041 | 14,035 | 14,002 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,980 | 11,144 | 11,552 | 11,646 | 11,648 | 11,643 | 11,630 | 11,614 | 11,612 | 11,601 | 11,599 | 11,592 | 11,575 | 11,586 | 11,566 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,946 | 11,110 | 11,398 | 11,590 | 11,622 | 11,619 | 11,591 | 11,615 | 11,674 | 11,677 | 11,627 | 11,655 | 11,682 | 11,637 | 11,600 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 13,064 | 13,272 | 14,749 | 15,017 | 14,955 | 14,886 | 14,890 | 14,867 | 14,818 | 14,794 | 14,743 | 14,708 | 14,631 | 14,690 | 14,622 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 13,531 | 14,266 | 14,507 | 14,320 | 14,253 | 14,221 | 14,379 | 14,026 | 14,226 | 14,142 | 14,175 | 14,035 | 14,196 | 14,095 | 14,082 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 13,333 | 13,990 | 13,960 | 13,753 | 13,691 | 13,666 | 13,804 | 13,529 | 13,654 | 13,574 | 13,621 | 13,497 | 13,648 | 13,557 | 13,552 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,932 | 13,011 | 14,308 | 14,507 | 14,441 | 14,398 | 14,382 | 14,377 | 14,324 | 14,302 | 14,331 | 14,307 | 14,235 | 14,292 | 14,233 |
| Cane Run 4 | 11,557 | 11,161 | 12,568 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,861 | 6,914 | 7,096 | 7,157 | 7,205 | 7,283 | 7,391 | 7,380 | 7,373 | 7,384 | 7,367 | 7,368 | 7,347 | 7,358 | 7,356 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,758 | 10,768 | 10,790 | 10,786 | 10,801 | 10,797 | 10,793 | 10,798 | 10,797 | 10,793 | 10,793 | 10,790 | 10,794 | 10,790 | 10,788 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,515 | 10,497 | 10,497 | 10,497 | 10,511 | 10,513 | 10,512 | 10,511 | 10,511 | 10,515 | 10,512 | 10,513 | 10,514 | 10,516 | 10,514 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,129 | 11,155 | 11,112 | 11,121 | 11,129 | 11,132 | 11,123 | 11,137 | 11,130 | 11,120 | 11,118 | 11,125 | 11,121 | 11,117 | 11,115 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,939 | 10,938 | 10,934 | 10,931 | 10,952 | 10,951 | 10,933 | 10,947 | 10,948 | 10,941 | 10,935 | 10,935 | 10,938 | 10,931 | 10,932 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,305 | 10,338 | 10,321 | 10,350 | 10,381 | 10,380 | 10,381 | 10,378 | 10,382 | 10,380 | 10,381 | 10,379 | 10,381 | 10,378 | 10,382 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,529 | 10,554 | 10,539 | 10,565 | 10,568 | 10,566 | 10,568 | 10,568 | 10,568 | 10,567 | 10,568 | 10,567 | 10,568 | 10,566 | 10,568 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,470 | 10,500 | 10,472 | 10,490 | 10,511 | 10,514 | 10,509 | 10,510 | 10,505 | 10,507 | 10,508 | 10,510 | 10,508 | 10,509 | 10,506 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,636 | 10,641 | 10,652 | 10,651 | 10,651 | 10,651 | 10,655 | 10,652 | 10,653 | 10,652 | 10,652 | 10,651 | 10,650 | 10,652 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,964 | 10,820 | 12,163 | 13,288 | 13,276 | 13,225 | 13,265 | 13,249 | 13,250 | 13,240 | 13,237 | 13,206 | 13,214 | 13,208 | 13,181 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,429 | 10,473 | 10,564 | 10,485 | 10,450 | 10,460 | 10,464 | 10,457 | 10,455 | 10,465 | 10,463 | 10,462 | 10,464 | 10,472 | 10,465 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 11,062 | 11,169 | 11,415 | 11,746 | 12,370 | 12,561 | 12,612 | 12,586 | 12,666 | 12,576 | 12,544 | 12,504 | 12,600 | 12,500 | 12,459 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 11,061 | 11,182 | 11,450 | 11,739 | 12,243 | 12,628 | 12,478 | 12,450 | 12,507 | 12,432 | 12,419 | 12,368 | 12,454 | 12,376 | 12,334 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 11,081 | 11,200 | 11,489 | 11,733 | 12,210 | 12,489 | 12,304 | 12,265 | 12,405 | 12,326 | 12,323 | 12,294 | 12,331 | 12,280 | 12,247 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 11,091 | 11,204 | 11,519 | 11,728 | 12,057 | 12,228 | 12,027 | 12,030 | 12,111 | 12,029 | 11,998 | 11,983 | 12,005 | 11,976 | 11,951 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 11,096 | 11,213 | 11,520 | 11,717 | 12,004 | 12,077 | 11,974 | 11,922 | 11,956 | 11,938 | 11,912 | 11,892 | 11,890 | 11,885 | 11,856 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,121 | 11,214 | 11,527 | 11,711 | 11,890 | 11,918 | 11,892 | 11,818 | 11,820 | 11,812 | 11,777 | 11,765 | 11,754 | 11,758 | 11,731 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |

| Scenario: Low Gas - Base Load | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 11,522 | 11,315 | 10,811 | 10,700 | 10,735 | 10,675 | 10,641 | 10,669 | 10,691 | 10,656 | 10,699 | 10,653 | 10,644 | 10,677 | 10,679 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,783 | 10,750 | 10,496 | 10,514 | 10,537 | 10,508 | 10,482 | 10,502 | 10,473 | 10,481 | 10,512 | 10,481 | 10,492 | 10,546 | 10,504 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,434 | 11,583 | 11,741 | 11,774 | 11,745 | 11,743 | 11,766 | 11,769 | 11,801 | 11,803 | 11,704 | 11,746 | 11,815 | 11,804 | 11,745 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,509 | 12,488 | 12,884 | 12,964 | 12,999 | 13,006 | 13,036 | 12,961 | 12,955 | 12,912 | 12,934 | 12,969 | 13,183 | 13,113 | 12,966 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,824 | 11,033 | 11,225 | 11,256 | 11,269 | 11,248 | 11,242 | 11,264 | 11,245 | 11,240 | 11,239 | 11,237 | 11,204 | 11,237 | 11,276 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,791 | 10,973 | 11,125 | 11,187 | 11,180 | 11,156 | 11,140 | 11,185 | 11,159 | 11,063 | 11,142 | 11,127 | 11,040 | 11,135 | 11,188 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,702 | 12,709 | 12,877 | 13,196 | 13,204 | 13,460 | 13,357 | 13,408 | 13,223 | 13,224 | 13,219 | 13,396 | 13,582 | 13,515 | 13,390 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,726 | 12,666 | 13,132 | 13,206 | 13,304 | 13,419 | 13,473 | 13,294 | 13,323 | 13,256 | 13,274 | 13,314 | 13,456 | 13,570 | 13,302 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,797 | 12,675 | 13,029 | 13,101 | 13,167 | 13,232 | 13,275 | 13,131 | 13,170 | 13,127 | 13,139 | 13,142 | 13,277 | 13,348 | 13,139 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,704 | 12,706 | 12,876 | 13,163 | 13,162 | 13,392 | 13,274 | 13,360 | 13,166 | 13,165 | 13,156 | 13,289 | 13,454 | 13,392 | 13,302 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,831 | 6,831 | 6,840 | 6,842 | 6,841 | 6,840 | 6,840 | 6,840 | 6,842 | 6,840 | 6,839 | 6,840 | 6,846 | 6,840 | 6,839 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,752 | 10,781 | 10,828 | 10,813 | 10,840 | 10,846 | 10,834 | 10,846 | 10,833 | 10,835 | 10,837 | 10,830 | 10,818 | 10,864 | 10,892 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,507 | 10,492 | 10,498 | 10,504 | 10,507 | 10,511 | 10,510 | 10,510 | 10,505 | 10,509 | 10,511 | 10,506 | 10,506 | 10,509 | 10,512 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,124 | 11,165 | 11,140 | 11,151 | 11,166 | 11,171 | 11,153 | 11,169 | 11,164 | 11,159 | 11,159 | 11,160 | 11,148 | 11,164 | 11,174 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,942 | 10,983 | 10,986 | 10,990 | 11,016 | 11,007 | 10,997 | 11,015 | 11,010 | 11,005 | 11,000 | 11,008 | 11,003 | 10,999 | 11,146 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,290 | 10,331 | 10,315 | 10,331 | 10,372 | 10,369 | 10,369 | 10,366 | 10,375 | 10,372 | 10,370 | 10,371 | 10,378 | 10,362 | 10,356 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,516 | 10,549 | 10,538 | 10,559 | 10,565 | 10,561 | 10,564 | 10,563 | 10,565 | 10,564 | 10,565 | 10,563 | 10,566 | 10,559 | 10,559 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,466 | 10,495 | 10,465 | 10,476 | 10,497 | 10,501 | 10,493 | 10,494 | 10,491 | 10,488 | 10,490 | 10,492 | 10,494 | 10,481 | 10,466 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,633 | 10,642 | 10,656 | 10,652 | 10,651 | 10,651 | 10,656 | 10,652 | 10,653 | 10,653 | 10,652 | 10,651 | 10,651 | 10,654 | 10,655 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,667 | 10,627 | 10,697 | 10,776 | 10,865 | 10,864 | 10,744 | 10,815 | 10,786 | 10,788 | 10,836 | 10,787 | 10,757 | 10,744 | 10,895 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,406 | 10,460 | 10,556 | 10,463 | 10,419 | 10,423 | 10,426 | 10,420 | 10,419 | 10,424 | 10,419 | 10,423 | 10,430 | 10,404 | 10,382 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,906 | 10,965 | 11,045 | 11,131 | 11,146 | 11,111 | 11,119 | 11,136 | 11,117 | 11,105 | 11,115 | 11,102 | 11,080 | 11,099 | 11,194 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,909 | 10,989 | 11,078 | 11,166 | 11,184 | 11,142 | 11,153 | 11,169 | 11,151 | 11,136 | 11,145 | 11,132 | 11,110 | 11,135 | 11,217 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 10,938 | 10,993 | 11,113 | 11,201 | 11,205 | 11,172 | 11,186 | 11,199 | 11,183 | 11,166 | 11,173 | 11,160 | 11,138 | 11,170 | 11,238 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 10,951 | 11,023 | 11,148 | 11,234 | 11,237 | 11,210 | 11,211 | 11,227 | 11,213 | 11,206 | 11,200 | 11,187 | 11,165 | 11,206 | 11,257 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 10,961 | 11,033 | 11,179 | 11,264 | 11,267 | 11,242 | 11,237 | 11,251 | 11,239 | 11,216 | 11,224 | 11,213 | 11,190 | 11,242 | 11,276 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 10,970 | 11,024 | 11,217 | 11,290 | 11,294 | 11,271 | 11,262 | 11,273 | 11,273 | 11,242 | 11,247 | 11,236 | 11,213 | 11,276 | 11,295 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 6,618 | 6,603 |

**Scenario: Low Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 11,456 | 11,235 | 10,765 | 10,658 | 10,702 | 10,690 | 10,661 | 10,674 | 10,700 | 10,677 | 10,690 | 10,660 | 10,669 | 10,635 | 10,652 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,763 | 10,721 | 10,475 | 10,485 | 10,515 | 10,524 | 10,503 | 10,504 | 10,490 | 10,498 | 10,508 | 10,487 | 10,498 | 10,500 | 10,488 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,396 | 11,547 | 11,715 | 11,740 | 11,717 | 11,767 | 11,766 | 11,741 | 11,775 | 11,780 | 11,709 | 11,735 | 11,803 | 11,732 | 11,720 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,473 | 12,456 | 12,829 | 12,908 | 12,956 | 13,123 | 13,004 | 12,979 | 12,934 | 12,919 | 12,921 | 12,993 | 13,211 | 12,985 | 12,905 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,792 | 11,002 | 11,174 | 11,211 | 11,226 | 11,194 | 11,279 | 11,285 | 11,274 | 11,271 | 11,266 | 11,264 | 11,239 | 11,256 | 11,242 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,766 | 10,952 | 11,091 | 11,156 | 11,147 | 11,091 | 11,185 | 11,205 | 11,192 | 11,137 | 11,181 | 11,175 | 11,107 | 11,167 | 11,163 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,674 | 12,681 | 12,844 | 13,127 | 13,145 | 13,480 | 13,389 | 13,444 | 13,242 | 13,252 | 13,242 | 13,439 | 13,644 | 13,434 | 13,303 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,691 | 12,635 | 13,083 | 13,158 | 13,281 | 13,709 | 13,384 | 13,295 | 13,256 | 13,244 | 13,239 | 13,309 | 13,415 | 13,307 | 13,236 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,756 | 12,646 | 12,985 | 13,056 | 13,144 | 13,472 | 13,194 | 13,132 | 13,118 | 13,116 | 13,114 | 13,141 | 13,247 | 13,139 | 13,086 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,676 | 12,679 | 12,840 | 13,094 | 13,102 | 13,423 | 13,302 | 13,393 | 13,186 | 13,189 | 13,181 | 13,327 | 13,507 | 13,324 | 13,222 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | 6980.3 | 6,831 | 6,831 | 6,840 | 6,842 | 6,841 | 6,840 | 6,840 | 6,840 | 6,842 | 6,840 | 6,839 | 6,840 | 6,845 | 6,840 | 6,839 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,750 | 10,769 | 10,811 | 10,798 | 10,820 | 10,839 | 10,846 | 10,856 | 10,859 | 10,869 | 10,863 | 10,861 | 10,830 | 10,857 | 10,870 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,513 | 10,493 | 10,503 | 10,508 | 10,510 | 10,506 | 10,510 | 10,505 | 10,504 | 10,506 | 10,509 | 10,507 | 10,496 | 10,505 | 10,509 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,110 | 11,146 | 11,124 | 11,130 | 11,147 | 11,170 | 11,189 | 11,203 | 11,176 | 11,171 | 11,178 | 11,178 | 11,188 | 11,173 | 11,164 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,924 | 10,953 | 10,960 | 10,957 | 10,980 | 10,978 | 11,018 | 11,032 | 11,039 | 11,046 | 11,033 | 11,036 | 11,006 | 11,028 | 11,102 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,296 | 10,339 | 10,326 | 10,342 | 10,376 | 10,365 | 10,358 | 10,357 | 10,365 | 10,358 | 10,356 | 10,359 | 10,371 | 10,364 | 10,361 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,517 | 10,553 | 10,543 | 10,561 | 10,566 | 10,559 | 10,557 | 10,557 | 10,560 | 10,558 | 10,560 | 10,557 | 10,563 | 10,559 | 10,561 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,468 | 10,500 | 10,473 | 10,485 | 10,503 | 10,500 | 10,481 | 10,486 | 10,474 | 10,472 | 10,472 | 10,475 | 10,482 | 10,474 | 10,471 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,632 | 10,643 | 10,655 | 10,652 | 10,651 | 10,651 | 10,656 | 10,652 | 10,653 | 10,653 | 10,653 | 10,652 | 10,651 | 10,654 | 10,654 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,636 | 10,591 | 10,667 | 10,727 | 10,817 | 10,922 | 10,834 | 10,895 | 10,872 | 10,872 | 10,901 | 10,867 | 10,835 | 10,849 | 10,853 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,413 | 10,471 | 10,560 | 10,481 | 10,437 | 10,415 | 10,395 | 10,396 | 10,388 | 10,393 | 10,389 | 10,392 | 10,398 | 10,395 | 10,392 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,872 | 10,913 | 10,999 | 11,070 | 11,087 | 11,064 | 11,190 | 11,199 | 11,188 | 11,174 | 11,178 | 11,167 | 11,146 | 11,155 | 11,146 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,878 | 10,939 | 11,029 | 11,106 | 11,126 | 11,083 | 11,217 | 11,223 | 11,213 | 11,199 | 11,201 | 11,191 | 11,169 | 11,180 | 11,169 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 10,908 | 10,945 | 11,059 | 11,141 | 11,146 | 11,119 | 11,243 | 11,244 | 11,235 | 11,222 | 11,223 | 11,213 | 11,192 | 11,203 | 11,191 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 10,922 | 10,974 | 11,091 | 11,173 | 11,178 | 11,162 | 11,260 | 11,264 | 11,255 | 11,253 | 11,243 | 11,233 | 11,213 | 11,224 | 11,210 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 10,933 | 10,987 | 11,118 | 11,204 | 11,208 | 11,201 | 11,283 | 11,281 | 11,274 | 11,262 | 11,261 | 11,252 | 11,232 | 11,243 | 11,229 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 10,943 | 10,984 | 11,154 | 11,232 | 11,235 | 11,240 | 11,305 | 11,298 | 11,300 | 11,282 | 11,278 | 11,269 | 11,250 | 11,261 | 11,247 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 |
| 2x1 NGCC | NA | NA | NA | NA | NA | NA | NA | NA | 6,641 | 6,616 | 6,630 | 6,613 | 6,610 | 6,608 | 6,603 | 6,626 | 6,601 | 6,586 |

| Scenario: Low Gas - Low Load | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| E.W. Brown 1 | 12,033 | 12,407 | 12,983 | 11,580 | 11,393 | 10,860 | 10,743 | 10,767 | 10,712 | 10,679 | 10,703 | 10,732 | 10,696 | 10,726 | 10,685 | 10,683 | 10,655 | 10,680 |
| E.W. Brown 2 | 10,729 | 10,675 | 11,142 | 10,800 | 10,775 | 10,517 | 10,542 | 10,557 | 10,532 | 10,510 | 10,526 | 10,501 | 10,508 | 10,531 | 10,503 | 10,515 | 10,520 | 10,510 |
| E.W. Brown 3 | 11,311 | 11,397 | 11,646 | 11,474 | 11,622 | 11,764 | 11,805 | 11,771 | 11,768 | 11,795 | 11,788 | 11,825 | 11,828 | 11,734 | 11,774 | 11,848 | 11,769 | 11,758 |
| E.W. Brown 5 | 24,417 | 16,513 | 13,490 | 12,549 | 12,521 | 12,939 | 13,023 | 13,041 | 13,062 | 13,085 | 13,025 | 13,002 | 12,964 | 12,977 | 13,038 | 13,276 | 13,033 | 12,946 |
| E.W. Brown 6 | 12,536 | 12,092 | 10,609 | 10,859 | 11,064 | 11,275 | 11,301 | 11,310 | 11,291 | 11,288 | 11,301 | 11,285 | 11,280 | 11,277 | 11,273 | 11,243 | 11,264 | 11,248 |
| E.W. Brown 7 | 12,127 | 11,182 | 10,605 | 10,817 | 10,994 | 11,159 | 11,218 | 11,212 | 11,190 | 11,176 | 11,212 | 11,190 | 11,089 | 11,175 | 11,160 | 11,063 | 11,152 | 11,157 |
| E.W. Brown 8 | 20,979 | 15,416 | 12,874 | 12,732 | 12,740 | 12,914 | 13,266 | 13,265 | 13,551 | 13,442 | 13,498 | 13,285 | 13,290 | 13,282 | 13,485 | 13,706 | 13,482 | 13,344 |
| E.W. Brown 9 | 17,924 | 16,309 | 13,215 | 12,761 | 12,698 | 13,176 | 13,256 | 13,320 | 13,461 | 13,519 | 13,351 | 13,363 | 13,307 | 13,312 | 13,364 | 13,516 | 13,373 | 13,283 |
| E.W. Brown 10 | 40,990 | 15,629 | 13,004 | 12,839 | 12,708 | 13,073 | 13,151 | 13,181 | 13,264 | 13,306 | 13,175 | 13,199 | 13,167 | 13,169 | 13,179 | 13,327 | 13,190 | 13,122 |
| E.W. Brown 11 | 30,238 | 15,911 | 13,569 | 12,734 | 12,733 | 12,915 | 13,232 | 13,222 | 13,475 | 13,351 | 13,446 | 13,230 | 13,228 | 13,219 | 13,369 | 13,564 | 13,369 | 13,260 |
| Cane Run 4 | 11,557 | 11,161 | 12,588 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 5 | 10,858 | 10,845 | 11,461 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 6 | 10,868 | 10,841 | 11,043 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Cane Run 7 | NA | NA | NA | 6,831 | 6,831 | 6,840 | 6,843 | 6,842 | 6,840 | 6,840 | 6,840 | 6,842 | 6,840 | 6,839 | 6,840 | 6,847 | 6,840 | 6,839 |
| Cane Run 11 | 42,874 | (5,919) | 56,474 | 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 | 10,784 | 10,823 | 10,698 | 10,751 | 10,804 | 10,851 | 10,835 | 10,869 | 10,876 | 10,864 | 10,876 | 10,860 | 10,864 | 10,863 | 10,857 | 10,841 | 10,854 | 10,853 |
| Ghent 2 | 10,696 | 10,688 | 10,629 | 10,502 | 10,493 | 10,496 | 10,502 | 10,510 | 10,515 | 10,511 | 10,514 | 10,507 | 10,511 | 10,512 | 10,507 | 10,502 | 10,506 | 10,511 |
| Ghent 3 | 11,080 | 10,912 | 11,003 | 11,139 | 11,187 | 11,158 | 11,173 | 11,186 | 11,192 | 11,170 | 11,189 | 11,181 | 11,177 | 11,178 | 11,180 | 11,169 | 11,172 | 11,165 |
| Ghent 4 | 11,051 | 10,912 | 10,930 | 10,966 | 11,023 | 11,018 | 11,033 | 11,061 | 11,048 | 11,036 | 11,059 | 11,052 | 11,050 | 11,039 | 11,052 | 11,043 | 11,028 | 11,049 |
| Green River 3 | 12,992 | 12,961 | 13,074 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Green River 4 | 11,155 | 11,397 | 10,712 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Haefling 1-2 (2) | 29,444 | 21,195 | 21,995 | 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 | 10,658 | 10,464 | 10,470 | 10,286 | 10,324 | 10,305 | 10,321 | 10,366 | 10,363 | 10,364 | 10,361 | 10,370 | 10,366 | 10,364 | 10,366 | 10,375 | 10,368 | 10,369 |
| Mill Creek 2 | 10,671 | 10,693 | 10,629 | 10,514 | 10,545 | 10,532 | 10,557 | 10,563 | 10,558 | 10,561 | 10,561 | 10,563 | 10,562 | 10,563 | 10,561 | 10,565 | 10,562 | 10,564 |
| Mill Creek 3 | 10,500 | 10,674 | 10,858 | 10,466 | 10,491 | 10,457 | 10,468 | 10,490 | 10,495 | 10,486 | 10,487 | 10,484 | 10,481 | 10,482 | 10,485 | 10,486 | 10,484 | 10,481 |
| Mill Creek 4 | 10,827 | 10,836 | 10,388 | 10,637 | 10,640 | 10,658 | 10,652 | 10,652 | 10,652 | 10,657 | 10,653 | 10,654 | 10,654 | 10,653 | 10,651 | 10,651 | 10,653 | 10,653 |
| Paddy's Run 11&12 | (29,554) | 28,983 | (13,051) | 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 | 11,327 | 11,145 | 10,809 | 10,699 | 10,664 | 10,728 | 10,829 | 10,914 | 10,908 | 10,791 | 10,867 | 10,833 | 10,837 | 10,882 | 10,835 | 10,801 | 10,814 | 10,824 |
| Trimble County 1 (75%) | 10,762 | 10,746 | 8,085 | 10,400 | 10,451 | 10,551 | 10,446 | 10,402 | 10,404 | 10,408 | 10,404 | 10,402 | 10,407 | 10,403 | 10,406 | 10,412 | 10,411 | 10,406 |
| Trimble County 2 (75%) | 9,369 | 9,300 | 6,919 | 9,177 | 9,178 | 9,186 | 9,185 | 9,185 | 9,187 | 9,185 | 9,185 | 9,185 | 9,185 | 9,187 | 9,187 | 9,187 | 9,187 | 9,187 |
| Trimble County 5 | 13,020 | 12,985 | 11,056 | 10,939 | 11,021 | 11,097 | 11,195 | 11,209 | 11,173 | 11,179 | 11,196 | 11,178 | 11,161 | 11,171 | 11,157 | 11,133 | 11,143 | 11,135 |
| Trimble County 6 | 12,796 | 11,958 | 10,791 | 10,939 | 11,042 | 11,134 | 11,231 | 11,244 | 11,207 | 11,214 | 11,228 | 11,212 | 11,193 | 11,201 | 11,187 | 11,163 | 11,174 | 11,165 |
| Trimble County 7 | 12,849 | 12,342 | 11,043 | 10,969 | 11,044 | 11,173 | 11,266 | 11,268 | 11,236 | 11,248 | 11,257 | 11,243 | 11,224 | 11,230 | 11,216 | 11,191 | 11,204 | 11,193 |
| Trimble County 8 | 12,590 | 12,854 | 11,149 | 10,981 | 11,073 | 11,212 | 11,298 | 11,301 | 11,274 | 11,271 | 11,282 | 11,271 | 11,265 | 11,256 | 11,243 | 11,218 | 11,232 | 11,219 |
| Trimble County 9 | 12,752 | 12,491 | 10,664 | 10,991 | 11,080 | 11,247 | 11,327 | 11,330 | 11,305 | 11,297 | 11,305 | 11,296 | 11,272 | 11,280 | 11,267 | 11,243 | 11,258 | 11,242 |
| Trimble County 10 | 12,513 | 12,634 | 11,331 | 11,000 | 11,066 | 11,286 | 11,352 | 11,355 | 11,331 | 11,325 | 11,325 | 11,328 | 11,298 | 11,301 | 11,288 | 11,266 | 11,280 | 11,264 |
| Zorn 1 | 25,887 | 40,436 | 20,388 | 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 facilty.

(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) 2013 | 2014 | 2015 | (PROJECTED) 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydro | Dix Dam 1-3 | 11/01/1925 | Built | 2029+ | 32 | 106,623 | 72,287 | 97,943 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 | 71,000 |
| Hydro | Ohio Falls 1-8 | 01/01/1928 | Built | 2029+ | 60 | 193,332 | 271,888 | 273,775 | 234,988 | 262,834 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 | 287,839 |
| Solar | Brown Solar | 06/01/2016 | Planned Build | 2029+ | 9 | NA | NA | NA | 11,087 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 | 15,216 |
| **Sub-total** | | | | | 92 | | | | | | | | | | | | | | | | | | |
| **Total Renewables** | | | | | 92 | | | | | | | | | | | | | | | | | | |

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

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand re:
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
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) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Energy Efficiency | Residential Conservation Program | 1998 | 2018 | 11 | 37,131 | 42,295 | 47,460 | 47,460 | 47,460 | 47,460 |
| Energy Efficiency | WeCare | 2001 | 2018 | 5 | 42,770 | 50,885 | 60,098 | 60,098 | 60,098 | 60,098 |
| Energy Efficiency | Commercial Conservation/Rebates | 1998 | 2018 | 156 | 329,991 | 374,012 | 418,033 | 418,033 | 418,033 | 418,033 |
| 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 | 106,475 | 106,475 | 106,475 | 0 | 0 | 0 |
| Energy Efficiency | Residential Refrigerator Removal | 2011 | 2018 | 5 | 32,850 | 40,350 | 47,850 | 47,850 | 47,850 | 47,850 |
| Energy Efficiency | Residential Incentives | 2011 | 2018 | 25 | 107,661 | 132,882 | 158,103 | 158,103 | 158,103 | 158,103 |
| Energy Efficiency | KSBA | 2013 | 2014 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **subtotal** | | | | **258** | **1,029,373** | **1,119,395** | **1,210,514** | **1,104,039** | **1,104,039** | **1,104,039** |
| 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** | **1,033,552** | **1,123,575** | **1,214,693** | **1,108,218** | **1,108,218** | **1,108,218** |

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand re:
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 hour:
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) 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Energy Efficiency | Residential Conservation Program | 1998 | 2018 | 11 | 47,460 | 47,460 | 47,460 | 47,460 |
| Energy Efficiency | WeCare | 2001 | 2018 | 5 | 60,098 | 60,098 | 60,098 | 60,098 |
| Energy Efficiency | Commercial Conservation/Rebates | 1998 | 2018 | 156 | 418,033 | 418,033 | 418,033 | 418,033 |
| 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 | 0 | 0 | 0 | 0 |
| Energy Efficiency | Residential Refrigerator Removal | 2011 | 2018 | 5 | 47,850 | 47,850 | 47,850 | 47,850 |
| Energy Efficiency | Residential Incentives | 2011 | 2018 | 25 | 158,103 | 158,103 | 158,103 | 158,103 |
| Energy Efficiency | KSBA | 2013 | 2014 | 0 | 0 | 0 | 0 | 0 |
| **subtotal** | | | | **258** | **1,104,039** | **1,104,039** | **1,104,039** | **1,104,039** |
| 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** | **1,108,218** | **1,108,218** | **1,108,218** | **1,108,218** |

(1) List each program within the 2 major categories of energy efficiency/conservation/consumption reduction and demand re:
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
Note: Copy as needed for additional resources.

Kentucky Utilities Company and Louisville Gas and Electric Company Sch13

UNIT PERFORMANCE DATA (1)

Unit Size (MW) Uprate and Derate

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Unit Name | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| E.W. Brown 1 | | | | | | | | | | | | | | | | | | |
| E.W. Brown 2 | | | | | | | | | | | | | | | | | | |
| E.W. Brown 3 | -2 | | | -3 | | | | | | | | | | | | | | |
| 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 | | | 668 | | | | | | | | | | | | | | | |
| Cane Run 11 | | | | | | | | | | | | | | | | | | |
| Dix Dam 1-3 | | | 2 | | | | | | | | | | | | | | | |
| Ghent 1 | | | -5 | | | | | | | | | | | | | | | |
| Ghent 2 | | | | | | | | | | | | | | | | | | |
| Ghent 3 | | -6 | -4 | | | | | | | | | | | | | | | |
| Ghent 4 | | | -4 | | | | | | | | | | | | | | | |
| Green River 3 | | | -68 | | | | | | | | | | | | | | | |
| Green River 4 | -2 | | -93 | | | | | | | | | | | | | | | |
| Haefling 1-3 | -12 | | | | | | | | | | | | | | | | | |
| Mill Creek 1 | | | -3 | | | | | | | | | | | | | | | |
| Mill Creek 2 | | | -4 | | | | | | | | | | | | | | | |
| Mill Creek 3 | | | | -6 | | | | | | | | | | | | | | |
| Mill Creek 4 | | | | | | | | | | | | | | | | | | |
| Ohio Falls 1 | | 2 | | | | | | | | | | | | | | | | |
| Ohio Falls 2 | | | 2 | | | | | | | | | | | | | | | |
| Ohio Falls 3 | 2 | | | | | | | | | | | | | | | | | |
| Ohio Falls 4 | | | | | 2 | | | | | | | | | | | | | |
| Ohio Falls 5 | | | 2 | | | | | | | | | | | | | | | |
| 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%) | | | | -4 | | | | | | | | | | | | | | |
| 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 | -71 | | | | | | | | | | | | | | | | | |
| Zorn 1 | | | | | | | | | | | | | | | | | | |

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

Kentucky Utilities Company and Louisville Gas and Electric Company
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 | 410 |
| 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 |
| Cane Run 7 | Louisville, KY | Turbine | Gas | 06/19/2015 | 668 |
| 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 | 495 |
| 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 | 383 |
| 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.

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) |
|---|---|---|---|---|---|
| 2x1 NGCC | Unknown | Turbine | Natural Gas | 2029 | 739 |

**Scenario: Mid Gas - High Load**

| Unit Name | Location | Unit Type | Primary Fuel Type | C.O.D. (2) | Size MW (3) |
|---|---|---|---|---|---|
| 2x1 NGCC | Unknown | Turbine | Natural Gas | 2021 | 739 |

**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) |
|---|---|---|---|---|---|
| SCCT | Unknown | Turbine | Natural Gas | 2029 | 200 |

**Scenario: High Gas - High Load**

| Unit Name | Location | Unit Type | Primary Fuel Type | C.O.D. (2) | Size MW (3) |
|---|---|---|---|---|---|
| 2x1 NGCC | Unknown | Turbine | Natural Gas | 2021 | 739 |

**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) |
|---|---|---|---|---|---|
| 2x1 NGCC | Unknown | Turbine | Natural Gas | 2029 | 739 |

**Scenario: Low Gas - High Load**

| Unit Name | Location | Unit Type | Primary Fuel Type | C.O.D. (2) | Size MW (3) |
|---|---|---|---|---|---|
| 2x1 NGCC | Unknown | Turbine | Natural Gas | 2021 | 739 |

**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.

**Kentucky Utilities Company and Louisville Gas and Electric Company** **Sch16**

**UNIT CAPACITY POSITION (MW)**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **Scenario: Mid Gas - Base Load** | | | | | | | | | | | | | | | | | | |
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 739 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 739 | 0 |
| **Unforced Availability** | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| **Net Generation Capacity** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 | 9,377 |

**Scenario: Mid Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Expected New Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 739 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 739 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,762 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

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**Scenario: Mid Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

**Scenario: High Gas - Base Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 200 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 200 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,223 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,838 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,838 | 9,377 |

**Scenario: High Gas - High Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Expected New Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 739 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 739 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,762 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

**Scenario: High Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

**Scenario: Low Gas - Base Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 739 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 739 | 0 |
| **Unforced Availability** | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| **Net Generation Capacity** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 | 9,377 |

| Scenario: Low Gas - High Load | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Expected New Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 739 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 739 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,762 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 9,377 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

**Scenario: Low Gas - Low Load**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Existing Capacity** | | | | | | | | | | | | | | | | | | |
| Conventional | 7,827 | 7,821 | 8,097 | 8,097 | 8,084 | 8,084 | 8,084 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 7,919 | 8,658 |
| Renewable | 86 | 88 | 92 | 92 | 100 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 | 104 |
| Total Existing Capacity | 7,913 | 7,909 | 8,189 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Planned Capacity Changes** | | | | | | | | | | | | | | | | | | |
| Conventional (1) | 0 | 0 | 0 | -13 | 0 | 0 | -165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Planned Capacity Changes | 0 | 0 | 0 | -13 | 4 | 0 | -165 | 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 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Expected New Capacity | 0 | 0 | 0 | 8 | 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** | 7,913 | 7,909 | 8,189 | 8,184 | 8,188 | 8,188 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,023 | 8,762 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | |
| Demand response | 0 | 0 | 0 | 343 | 357 | 372 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 | 380 |
| Conservation/Efficiency | 0 | 0 | 0 | 201 | 221 | 244 | 246 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Total Existing DSM Reductions | 0 | 0 | 0 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **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 | 544 | 578 | 617 | 626 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 | 616 |
| **Net Generation & Demand-side** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |
| **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** | 7,913 | 7,909 | 8,189 | 8,728 | 8,766 | 8,804 | 8,649 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 8,638 | 9,377 |

(1) In 2014, Planned Capacity Changes for Conventional resources include updates to unit rating assumptions.

**Kentucky Utilities Company and Louisville Gas and Electric Company**
**CONSTRUCTION FORECAST (Million Dollars)**

| | ACTUAL EXPENDITURES | | | PROJECTED EXPENDITURES (1) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **I. New Traditional Generating Facilities** | | | | | | | | | | | | | | | | | | |
| a. Capital Investment (Exclusive of AFUDC) | 0 | 0 | 0 | 222 | 281 | 346 | 271 | 262 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| b. AFUDC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| c. Annual Total | 0 | 0 | 0 | 222 | 281 | 346 | 271 | 262 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| d. Cumulative Total | 0 | 0 | 0 | 222 | 503 | 849 | 1120 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 | 1382 |
| **II. New Renewable Generating Facilities (2)** | | | | | | | | | | | | | | | | | | |
| a. Capital Investment (Exclusive of AFUDC) | 0 | 0 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| b. AFUDC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| c. Annual Total | 0 | 0 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| d. Cumulative Total | 0 | 0 | 0 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **III. Other Facilites** | | | | | | | | | | | | | | | | | | |
| a. Transmission | 38 | 40 | 39 | 68 | 79 | 82 | 83 | 149 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| b. Distribution | 59 | 72 | 55 | 93 | 109 | 103 | 121 | 122 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| c. Energy conservation/efficiency & demand response | 131 | 705 | 933 | 39 | 40 | 33 | 28 | 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| d. AFUDC | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Annual Total | 228 | 817 | 1,027 | 200 | 228 | 218 | 232 | 301 | - | - | - | - | - | - | - | - | - | - |
| f. Cumulative Total | 228 | 1,045 | 2,073 | 200 | 428 | 646 | 878 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 | 1179 |
| **IV. Total Construction Expenditures** | | | | | | | | | | | | | | | | | | |
| a. Annual | 228 | 817 | 1,027 | 428 | 509 | 564 | 503 | 563 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| b. Cumulative | 228 | 1,045 | 2,073 | 428 | 937 | 1501 | 2004 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 | 2567 |
| **V. Percent of Funds for Total Construction Provided from External Financing (3)** | 45% | 38% | 46% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

(1) This information is provided for 2016-2019 and represents major generation and environmental projects at the Cane Run, Trimble County, Green River, and E.W. Brown facilities

(2) Construction of a 10 MW solar photovoltaic facility at the E.W. Brown facility

(3) Actual expenses for 2013-2015 include generation, distribution, transmission, environmental, and other capital projects

(4) Represents year ending total debt divided by total capitalization

2016 IRP

Kentucky Utilities Company and Louisville Gas and Electric Company — Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

| Scenario: Mid Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

| Scenario: Mid Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

* To reflect total dispatch costs, including any variable O and environmental or compliance costs.
** Per definition of §56-576 of the Code of Virginia.

CONFIDENTIAL INFORMATION HIGHLIGHTED

Kentucky Utilities Company and Louisville Gas and Electric Company
FUEL DATA



CONFIDENTIAL INFORMATION REDACTED

| *Scenario: Mid Gas - Low Load* | *(ACTUAL)* | | | *(PROJECTED)* | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

| Scenario: High Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

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** Per definition of §56-576 of the Code of Virginia.

CONFIDENTIAL INFORMATION HIGHLIGHTED

**Scenario: High Gas - High Load**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

**Scenario: High Gas - Low Load**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

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** Per definition of §56-576 of the Code of Virginia.

| Scenario: Low Gas - Base Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

| Scenario: Low Gas - High Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

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** Per definition of §56-576 of the Code of Virginia.

CONFIDENTIAL INFORMATION HIGHLIGHTED

Kentucky Utilities Company and Louisville Gas and Electric Company  Sch18

FUEL DATA

CONFIDENTIAL INFORMATION REDACTED

| Scenario: Low Gas - Low Load | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **Delivered Fuel Price (cents/MBtu)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| **Primary Fuel Expenses (cents/kWh)*** | | | | | | | | | | | | | | | | | | |
| a. Nuclear | [redacted] | | | [redacted] | | | | | | | | | | | | | | |
| b. Coal | | | | | | | | | | | | | | | | | | |
| c. Heavy Fuel Oil | | | | | | | | | | | | | | | | | | |
| d. Light Fuel Oil | | | | | | | | | | | | | | | | | | |
| e. Natural Gas | | | | | | | | | | | | | | | | | | |
| f. Renewable** | | | | | | | | | | | | | | | | | | |
| g. Purchases Energy Charges Only | | | | | | | | | | | | | | | | | | |
| h. Purchases Energy and Capacity Charges | | | | | | | | | | | | | | | | | | |

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