**COMMONWEALTH OF KENTUCKY**
**BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

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| ELECTRONIC 2023 INTEGRATED | ) | |
| RESOURCE PLAN OF BIG RIVERS | ) | CASE NO. 2023-00310 |
| ELECTRIC CORPORATION | ) | |

**COMMENTS OF JOINT INTERVENORS**
**KENTUCKIANS FOR THE COMMONWEALTH AND KENTUCKY RESOURCES COUNCIL**


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***Public Version***

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Joint Intervenors Kentuckians for the Commonwealth and Kentucky Resources Council submit the following comments regarding Big Rivers Electric Corporation's ("Big Rivers" or "Company") 2023 Integrated Resource Plan ("IRP").

## I. INTRODUCTION

This IRP comes at a time of exciting opportunities for utilities, and especially rural electric cooperatives, interested in building out a cleaner, more affordable, and more reliable energy portfolio. In particular, the 2022 Inflation Reduction Act has made available an unprecedented federal investment of hundreds of billions of dollars in grants, tax incentives, low-interest loans and other financial support for renewable energy and storage projects, energy efficiency and distributed generation especially for low-income utility customers, transmission improvements, and debt modification or refinancing for stranded fossil generation assets. Especially given that residential and commercial customers who are served by Big Rivers' generation are facing some of the highest electric rates in the state, one would expect Big Rivers' IRP to reflect a serious effort to maximize its benefits from the IRA. However, in its only notable example in the IRP of such effort, Big Rivers has sought and been invited to apply for financial support of a proposed 100 MW solar and 50 MW storage project that the IRP assumes comes online in 2028. Combined with the Unbridled Solar PPA that has already been approved, Big Rivers projects it would generate approximately 5 to 8% of its energy from solar per year, which is a positive start.

Unfortunately, the rest of the IRP is a status quo document that fails to reasonably evaluate, much less plan to pursue, a cleaner, more affordable, and more reliable energy portfolio. For example, the IRP:

- Assumes without any analysis the continued operation of the Wilson coal plant until at least 2045 while failing to account for numerous potential environmental regulatory costs and risks facing the plant.

- Focuses almost all of its request for IRA grants and loans on a flawed $2.5 billion proposal to install and operate carbon capture and sequestration ("CCS") on the Wilson plant.

- Unreasonably constrains the consideration of renewables and storage in ways that prevented such resources from fairly competing with the 635 MW gas combined cycle plant that Big Rivers proposes to bring online in 2029.

- Presents a demand side management ("DSM") potential study that, while marred by flaws that leads it to underestimate energy savings potential and overestimate costs, finds that substantial energy savings could be achieved at a 3 to 1 benefit-to-cost ratio. Despite this result, the IRP assumes no DSM programs throughout the planning period, and Big Rivers has not identified plans to pursue any of these cost-effective programs.

- Projects that starting in 2030, Big Rivers would have significantly more generation, and more capacity, than it needs to serve its native system load, thereby subjecting its customers to largely unexplored economic risks.

Joint Intervenors' comments are informed in substantial part by the work of experts Chelsea Hotaling and Dan Mellinger of Energy Futures Group, whose report (hereinafter the "EFG Report") is attached to and adopted in full as part of these comments.[1] Joint Intervenors offer the EFG Report and the following comments to further detail our concerns about Big Rivers' IRP, and to offer recommendations on ways the planning process could be improved moving forward. Joint Intervenors' silence on any issue, analysis, or conclusion advanced in Big Rivers' IRP should not be taken as support or agreement.

[1] C. Hotaling and D. Mellinger, *Report on Big Rivers Electric 2023 Integrated Resource Plan* (March 8, 2024), attached as Exhibit 1.

## II. BIG RIVERS SHOULD FACILITATE A ROBUST STAKEHOLDER ENGAGEMENT PROCESS FOR FUTURE IRP FILINGS

As discussed in the EFG Report, Big Rivers should facilitate a much more robust stakeholder process for future IRP filings, which can help ensure a more collaborative and transparent resource planning process.[2] Joint Intervenors urge Big Rivers, as a critically important component of expanding stakeholder engagement, to identify and engage with underserved communities who have not historically been engaged with their process. As resources to help guide such an approach to stakeholder engagement, Joint Intervenors recommend that Big Rivers consult with the National Renewable Energy Laboratory's ("NREL") best practices for community engagement,[3] as well as Facilitating Power's *The Spectrum of Community Engagement to Ownership*.[4]

NREL's best practices provide recommendations for how Big Rivers should approach a community-centered energy planning process. The first step is to identify and convene stakeholders and encourage them to form a leadership team to discuss an energy vision and specific energy goals.[5] These steps are the beginning of what NREL describes as the community energy planning cycle, which is pictured below.[6]

[2] EFG Report, Section 2.
[3] Liz Ross and Megan Day, *Community Energy Planning: Best Practices and Lessons Learned in NREL's Work with Communities*, Nat'l Renewable Energy Lab. (Aug. 1, 2022), https://www.nrel.gov/docs/fy22osti/82937.pdf ("NREL").
[4] Rosa Gonzalez, *The Spectrum of Community Engagement to Ownership*, Facilitating Power (2019), https://movementstrategy.org/wp-content/uploads/2021/08/The-Spectrum-of-Community-Engagement-to-Ownership.pdf.
[5] NREL at 3.
[6] *Id.*

***Figure 1 – Community Energy Planning Cycle***


*The Spectrum of Community Engagement to Ownership* is a tool to assist in identifying the different stages along a ladder of engagement toward centering community participation in decision making. This resource helps to identify the tangible, concrete differences between (1) informing a community; (2) consulting a community; (3) involving a community; (4) collaborating with a community; and (5) deferring to a community. At each step along the way, actions are taken to deepen relationships and create greater participation and equity from the community.

In addition to the specific steps recommended by EFG to significantly increase stakeholder engagement and participation in development of future IRPs, Joint Intervenors urge

Big Rivers and the Commission to give full consideration to these resources that provide guidance for how to more broadly and meaningfully engage with communities impacted by energy planning decisions.

## III. IRP STANDARDS

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires Big Rivers to submit, every three years, a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of utility's system.[7] Core elements of the filing include:

- A base load forecast that is "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system."[8]
- A "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost," and that includes consideration of "key uncertainties" and an "assessment of potentially cost-effective resource options available to the utility."[9]
- The revenue requirements and average system rates resulting from the plan set forth in the IRP.[10]

As the Commission Staff stated in reviewing Big Rivers' 2020 IRP filing, the Commission's goal in establishing the IRP requirement:

> was to ensure that all reasonable options for the future supply of electricity were being examined in order to provide ratepayers a reliable supply of electricity at the lowest possible cost.[11]

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[7] 807 K.A.R. 5:058 Section 1(2).
[8] 807 K.A.R. 5:058 Section 7(3).
[9] 807 K.A.R. 5:058 Section 8(1).
[10] 807 K.A.R. 5:058 Section 9.
[11] Case No. 2020-00299, *Staff Report on the 2020 Integrated Resource Plan of Big Rivers Electric Corporation*, at 2 (Ky. P.S.C. Nov. 22, 2021).

Consistent with this Commission goal, Staff has explained that two of its goals in reviewing an IRP are to ensure that:

1. All resource options are adequately and fairly evaluated;
2. Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable.[12]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable,"[13] as utility customers do not have "the right to price shop for the most affordable electric rates" and, therefore, "must rely on the Commission to protect them from unreasonable and unfair rates."[14] As the Commission has explained, it has long been recognized that "'least cost' is one of the fundamental principles utilized when setting rates that are fair, just, and reasonable."[15] A utility's rates will almost certainly not be fair, just, and reasonable if they do not result from planning processes that seek to identify a resource plan that is low-cost and low-risk for customers.

Unfortunately, as detailed in these comments and the attached EFG Report, Big Rivers' IRP fails in a number of critical ways to provide an adequate and reasonable evaluation of all resource options or evidence an attempt to ensure that its Members' customers receive a reliable supply of energy at the lowest possible cost.

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[12] *Id.* at 4.
[13] KRS § 278.030(1); *Ky. Pub. Serv. Comm'n v. Commonwealth ex rel. Conway,* 324 S.W.3d 373, 377 (Ky. 2010).
[14] *Ky. Indus. Util. Customers, Inc. v. Ky. Pub. Serv. Comm'n*, 504 S.W.3d 695, 705 (Ky. Ct. App. 2016).
[15] Case No. 2009-00545, *In the Matter of: Application of Kentucky Power Co.*, Order at 5 (Ky. P.S.C. June 28, 2010).

## IV. RESIDENTIAL AND COMMERCIAL CUSTOMERS OF BIG RIVERS' MEMBERS HAVE EXPERIENCED RAPIDLY INCREASING ELECTRIC BILLS SINCE 2009

The IRP goal of providing a reliable supply of electricity at the lowest possible cost does not, of course, mean that rates and monthly electric bills will never increase. It does, however, suggest that if a utility's ratepayers are experiencing significant electric bill increases, especially in comparison to those experienced by ratepayers of other utilities in the state, the thorough evaluation of the utility's resource planning required by the IRP regulations is especially critical.

Unfortunately, significant increases in electric bills are exactly what the residential customers of Big Rivers' three Members – Kenergy, Jackson Purchase Energy Corporation, and Meade County RECC – have experienced. As shown in Table 1 below, both the electric rates and monthly electric bills paid by such residential customers have approximately doubled between 2009 and 2022.

**Table 1: Residential Rates and Monthly Bills, 2009-2022**

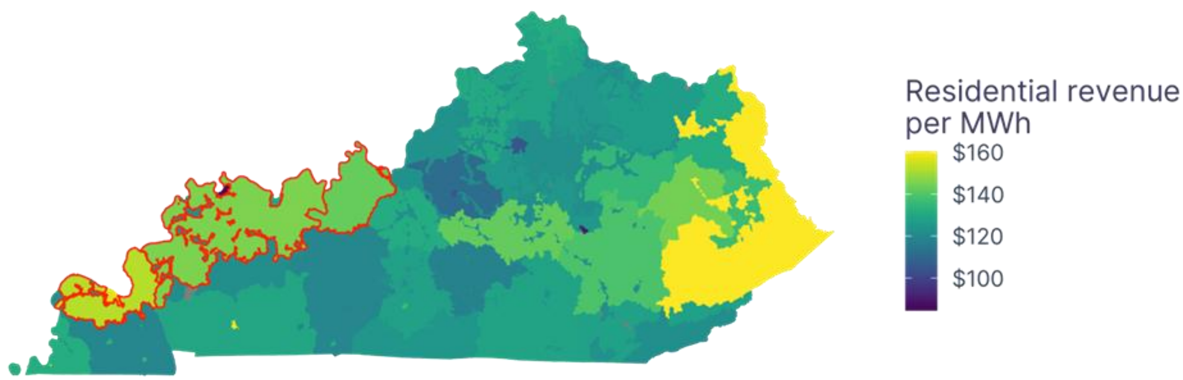
| | 2009[16] | 2014[17] | 2018[18] | 2020[19] | 2022[20] |
|---|---|---|---|---|---|
| Kenergy Rates (cents/kWh) | 7.07 | 9.78 | 12.47 | 12.47 | 14.56 |
| Kenergy Monthly Bill | $92.98 | $136.27 | $165.23 | $170.21 | $182.29 |
| Jackson Purchase Rates (cents/kWh) | 7.03 | 9.65 | 11.96 | 12.06 | 15.23 |
| Jackson Purchase Monthly Bill | $87.34 | $126.77 | $152.76 | $135.00 | $182.30 |
| Meade County RECC Rates (cents/kWh) | 6.99 | 9.95 | 12.31 | 12.20 | 14.29 |
| Meade County RECC Monthly Bill | $74.40 | $113.99 | $133.53 | $118.56 | $146.75 |

Notably, while in 2008 the residential customers of Big Rivers' members were paying rates below the 7.94 cents/kWh state average for residential customers,[21] by 2020 their rates were considerably above the state average of 10.05 cents/kWh.[22] And in 2022, monthly electric bills

[16] Ky. Energy & Env't Cabinet, Kentucky Energy Profile 2010, at 37–38, ("2010 Energy Profile") https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202010.pdf (last accessed Mar. 7, 2024) ("2010 Energy Profile").
[17] Ky. Energy & Env't Cabinet, Kentucky Energy Profile 2015, at 20–21, https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202015.pdf (last accessed Mar. 7, 2024).
[18] Ky. Energy & Env't Cabinet, Kentucky Energy Profile 2019, at 11–12, https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf (last accessed Mar. 7, 2024).
[19] Ky. Energy & Env't Cabinet, Kentucky Energy Profile 2023, at 11–12, https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202023.pdf (last accessed Mar. 7, 2024) ("2023 Energy Profile"). While previous Kentucky Energy Profiles reported data through the year before the publication of the profile, the 2023 Profile reports data only through 2020. *Id.*
[20] U.S. Energy Info. Admin., Annual Electric Power Industry Report, Form EIA-861 (Oct. 5, 2023), https://www.eia.gov/electricity/data/eia861/. The residential rates and monthly bills for each Big Rivers member were calculated from the Residential Revenues, Sales, and Customers data provided in the Sales_Ult_Cust_2022 file. *Id.* at 2022 final data ZIP folder (https://www.eia.gov/electricity/data/eia861/zip/f8612022.zip).
[21] 2010 Energy Profile at 33.
[22] 2023 Energy Profile at 10.

for residential customers in Big Rivers' service territory – especially those served by Jackson Purchase and Kenergy – were exceeded in Kentucky only by those in the eastern part of the state, as shown in the following map, highlighting Big Rivers' members' territory in red:

***Figure 2 – Residential Revenue per MWh in Kentucky***[23]




Commercial customers of Big Rivers' Members have similarly seen substantial increases in their electric rates. In 2009, the rates for Kenergy, Jackson Purchase, and Meade County RECC commercial customers were 6.82, 6.08, and 7.16 cents/kWh, respectively, which was below the 2008 state average of 7.29 cents/kWh.[24] By 2020, those rates were 11.65, 10.38, and 11.79 cents/kWh, respectively, well above the state average of 9.28 cents/kWh.[25]

In short, at least for residential and commercial ratepayers, from 2009 to 2020, Big Rivers and its Members have gone from having some of the lowest rates in Kentucky to some of

[23] Revenue data from EIA Form 861 for 2022, https://www.eia.gov/electricity/data/eia861/, specifically the spreadsheet "Sales_ult_Cust_2022.xlsx" was used, multiplying column J, ("Residential", "Revenues", "Thousand Dollars"), by 1000 to obtain total revenue, and dividing by column K, ("Residential", "Sales", "Megawatthours") to obtain revenues per megawatt hour. Utility territory GIS data from https://opengisdata.ky.gov/datasets/kygeonet::ky-electric-service-areas/about.
[24] 2010 Energy Profile at 33, 39.
[25] 2023 Energy Profile at 10–12.

the highest. This trend raises significant questions, mostly unaddressed by Big Rivers, about whether a largely status quo resource plan such as that presented in the IRP is reasonable.

## V. BIG RIVERS CONTINUES TO UNREASONABLY FAIL TO PURSUE COST-EFFECTIVE DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS THAT COULD REDUCE ELECTRIC BILLS.

In the face of the increasing electric bills confronting the residential and commercial customers of Big Rivers' Members, the IRP unreasonably dismisses one of the best options for helping customers reduce their electric bills – demand side management ("DSM") and energy efficiency ("EE"). Decades of DSM and EE programming at utilities throughout the country have demonstrated that DSM-EE saves money for customers because the cheapest kilowatt hour of electricity is the one that does not need to be generated. For example, a 2021 study found that the industry-wide levelized cost of energy savings from utility efficiency investments was approximately $0.024 per kilowatt hour saved in 2018,[26] while an evaluation of 11,796 DSM-EE programs from utilities through the country found a levelized cost of $0.026 per kilowatt hour saved from 2010 through 2018.[27] The significant benefit to customers of such low-cost DSM-EE programs has been recognized by this Commission, which recently explained:

> DSM-EE programs are cost-effective in reducing demand and energy. Said differently, every dollar spent on DSM-EE programs returns benefits to customers in excess of a dollar. Given their cost-

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[26] Charlotte Cohn, *The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-Funded Efficiency Programs in 2018*, ACEEE: Policy Brief, at 1 (June 2021), https://www.aceee.org/sites/default/files/pdfs/cost_of_saving_electricity_final_6-22-21.pdf.

[27] Chandler Miller et al., *Efficiency Through the Years: Program Cost and Impact in the 2010s*, Berkeley Lab, at 6 (Oct. 21, 2021), https://eta-publications.lbl.gov/sites/default/files/aceee_cose_cspd_analysis-final.pdf.

> effectiveness, customers rates over time are lower with DSM-EE programs than they would have been without them.[28]

Despite these and other significant benefits of DSM-EE,[29] the preferred resource plan set forth in Big Rivers' IRP inexplicably fails to include any DSM-EE programs during the entire 15-year planning period.

To its credit, Big Rivers did include with its IRP a DSM market potential study ("MPS") that provides estimates of the utility's technical, economic, achievable, and program potential DSM energy and peak demand savings from 2024-2033.[30] As detailed in the attached EFG Report, however, the MPS is riddled with flawed assumptions and analyses that lead it to significantly underestimate the savings potential and overestimate the costs of potential Big Rivers DSM programs. As summarized in the EFG Report, the flaws in the MPS include:

1. **MPS Measure List**: The MPS failed to consider the potential benefits from a more comprehensive list of DSM measures.
2. **Qualitative Screening**: Measures were eliminated from the MPS subjectively, using a "qualitative screening" analysis prior to the quantitative economic analysis of cost-effectiveness.
3. **Technical Potential**: The Technical Potential was limited by the measure list and assumptions regarding availability.

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[28] Case No. 2022-00402, *In the Matter of: Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Order at 173 (Ky. P.S.C. Nov. 6, 2023) ("LG&E-KU CPCN Case Nov. 6 2023 Order").

[29] For example, DSM-EE has been recognized as an effective tool for reducing ratepayer exposure to energy and fuel price volatility. Brendon Baatz & Brian Stickles, *Estimating the Value of Energy Efficiency to Reduce Wholesale Energy Price Volatility*, ACEEE, at iii (Apr. 10, 2018), https://www.aceee.org/research-report/u1803; David Hoppock & Dalia Patino Echeverri, *Using Energy Efficiency to Hedge Against Natural Gas Price Uncertainty*, Nicholas Inst. for Env't Pol'y Solutions (Jan. 2013), https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-02.pdf.

[30] Case No. 2023-00310, Big Rivers Electric Corp., 2023 Integrated Resource Plan, Appendix B at 1–2 (Sept. 29, 2023), https://psc.ky.gov/pscecf/2023-00310/senthia.santana%40bigrivers.com/09292023125957/2023_IRP_and_Appendices_Redacted.pdf ("Big Rivers 2023 IRP").

4. **Economic Potential**: The MPS failed to adequately consider the benefits and costs, resulting in an unusually large loss of savings during the economic screen
5. **Achievable Potential**: The calculation of achievable potential includes inappropriate adjustments for the participant cost test and other financial barriers.
6. **Program Potential**: The size of the Program Potential scenario is arbitrary, and the portfolio was not optimized for cost and savings.
7. **Inflation Reduction Act**: The MPS failed to consider the influence of the Inflation Reduction Act ("IRA") on incentives and measure adoption.
8. **MPS Reference Sources**: The MPS used multiple outdated reference sources.[31]

We will not repeat or further summarize here the analysis of the MPS that is set forth in the EFG Report. Instead, we write to highlight that even with its underestimates of savings potential and overestimates of costs, the MPS found that substantial levels of savings could be achieved by Big Rivers through programs for which benefits to customers significantly outweigh costs. In particular, the MPS evaluated, among other things, Big Rivers' achievable potential, which is defined as the amount of DSM-EE that is technically feasible, cost effective, and able to be implemented after considering real-world barriers to end-user adoption and challenges to ramping up utility programs.[32] The MPS then assessed the economic impact of such achievable potential under four different benefit-cost tests, including the Total Resource Cost ("TRC"),[33] which measures benefits and costs from the perspective of all utility customers in the service territory and is the test that the Commission had traditionally used in evaluating DSM-EE programs.[34] Through such analyses, the MPS found an achievable potential savings of 10% of energy use and 41 MW of peak demand,[35] with a TRC benefit-cost ratio of 3.0 from $96 million

[31] EFG Report at 26-27.
[32] Big Rivers 2023 IRP, Appendix B at 1-7, 2-10.
[33] *Id.*, Appendix B at 1-5.
[34] LG&E-KU CPCN Case Nov. 6 2023 Order at 156.
[35] Big Rivers 2023 IRP at 79-80.

in spending through 2033.[36] Despite such a positive benefit-cost ratio and significant savings, however, Big Rivers did not model or otherwise evaluate the achievable potential scenario further. Instead, Big Rivers considered only a $1 million per year DSM program, which would lead to savings of 4% of energy use and 16 MW of peak demand by 2033 at a TRC ratio of 3.1.[37] Despite these positive results, Big Rivers declined to include any DSM-EE programs in its proposed resource plan.

Big Rivers did not provide any justification for its failure to evaluate or pursue the levels of DSM-EE that its own MPS showed would produce significant benefits for its Members' customers. When asked why it evaluated only a $1 million DSM program, Big Rivers offered only that doing so was consistent with the approach taken in past IRPs.[38] When asked why it did not evaluate a higher annual program budget (such as $2 million or $4 million) or the achievable potential, Big Rivers added only that it "believes" that the $1 million annual budget "is a reasonable amount."[39] The Company was similarly non-responsive when asked why it had not proposed any DSM-EE programs yet and whether it anticipated doing so in the next three years, stating only that "Big Rivers will continue to evaluate energy efficiency programs and will seek Commission approval of any new programs to the extent such approval is required by law."[40] Such cursory responses hardly qualify as reasonable justification for Big Rivers leaving so much potential savings on the table.

[36] Big Rivers Response to Joint Intervenors' Request No. 1-30.
[37] Big Rivers 2023 IRP at 79–81.
[38] Big Rivers Response to Joint Intervenors Request No. 1-45; Big Rivers Response to Staff Request No. 2-38.
[39] Big Rivers Response to Joint Intervenors Request No. 1-45.
[40] Big Rivers Response to Joint Intervenors Request No. 1-32(b). As explained in the EFG Report, there are various reasons why the IRP model did not select the $1 million DSM program, but such non-selection is not a reason to reject the cost-effective DSM identified in the MPS. EFG Report at 20-21.

Big Rivers' approach to DSM-EE in this IRP is almost identical to how it handled the issue in its 2020 IRP. The potential study that Big Rivers included with that IRP found an achievable potential of savings of 11% of energy use and 53 MW of demand by energy savings by 2030.[41] While no TRC results were provided for the achievable potential scenario, the 2020 potential study found TRC benefit-cost ratios of 2.5 for a $2 million per year DSM scenario, and 2.7 for a $1 million per year scenario.[42] Despite these positive results, Big Rivers declined to include any DSM-EE programs in its 2020 resource plan and, instead, said that it would continue to evaluate such programs.[43]

As rates and monthly bills have continued to rise for residential and commercial customers of Big Rivers' Members, the questions must be asked why Big Rivers has not seized the cost-saving opportunities presented by DSM-EE, and when will it do so.

## VI. BIG RIVERS UNREASONABLY FAILED TO EVALUATE DISTRIBUTED ENERGY RESOURCES

Distributed energy resources ("DERs") serve as a low-cost resource that can supply capacity requirements, reduce fuel price volatility, improve reliability of the distribution grid, increase resilience, and overcome barriers to deployment of new resources. In this IRP, Big Rivers did not conduct a comprehensive analysis of DERs, thereby overlooking huge potential

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[41] Case No. 2020-00299, Big Rivers Electric Corp, 2020 Integrated Resource Plan, 82–83 (Sept. 21, 2020), https://psc.ky.gov/pscecf/2020-00299/roger.hickman%40bigrivers.com/09212020071904/Big_Rivers_2020_IRP_with_Appendices.pdf ("Big Rivers 2020 IRP").
[42] *Id.* at 83.
[43] *Id.* at 89–90.

for the Company to tap into to meet future capacity needs. DERs can provide a number of resiliency benefits as well, if they are designed to do so.[44]

The experiences of other states have shown that, compared to the residential sector, the commercial and industrial ("C&I") sectors have a much larger potential for hosting battery capacity, which can also be deployed quickly. For example, in Massachusetts, the C&I sector has 100 times as much battery capacity as the residential sector.[45] If Big Rivers deployed a battery program with similar rates of uptake by C&I customers as Massachusetts has experienced, the Company could have substantial installed battery capacity at customer locations by 2030, with all the attendant resilience benefits on top of the capacity and reliability values.

DERs are great tools to support Big Rivers and its customers. DERs reduce Big Rivers' reliance on fossil fuel generation, thereby reducing customer exposure to fuel price volatility. Battery storage systems can provide back-up power to homes and critical community facilities, like nursing homes and schools. Solar plus storage systems provide an even greater level of resilience, as such systems can operate indefinitely during grid outages, with the solar array re-charging the battery and the battery enabling the solar power to be used directly even when the grid is down.

Big Rivers should not shy away from fully analyzing the potential for DERs within its IRP and continue to engage with stakeholders about advancing DERs. Specific areas that Big

[44] *See* Kiera Zitelman, *Advancing Electric System Resilience with Distributed Energy Resources: A Review of State Policies*, Nat'l Ass'n of Reg. Util. Comm'rs, at 9 (Apr. 2020), https://pubs.naruc.org/pub/ECD7FAA5-155D-0A36-3105-5CE60957C305 (identifying characteristics of resilient DERs). Resilient DERs offer distinct advantages from 'non-resilient' DERs – those not designed with resilience as an explicit objective – including dispatchability, islanding capability, siting at critical loads/locations, fuel security, and quick ramping. All DERs, resilient or not, are decentralized and offer benefits distinct from large generators.

[45] Bryndis Woods et al., *ConnectedSolutions: A Program Assessment for Massachusetts,* Applied Econ. Clinic, at 18–21 (Sept. 2021), https://www.cleanegroup.org/wp-content/uploads/ConnectedSolutions-An-Assessment-for-Massachusetts.pdf.

Rivers and community partners can collaborate on include public education, consumer protection, permitting and codes, and workforce development.

## VII. BIG RIVERS HAS UNREASONABLY FAILED TO FULLY PURSUE THE COST-SAVING OPPORTUNITIES PROVIDED BY THE INFLATION REDUCTION ACT.

The 2022 Inflation Reduction Act ("IRA"), along with provisions of the 2021 Bipartisan Infrastructure Law ("BIL"), provide an unprecedented federal investment in rebuilding our nation's electric system, with a focus on supporting utilities and consumers in transitioning to clean energy, reducing emissions, and saving ratepayers money on their electric bills.[46] The combination of grants, tax credits, loans, and other incentives are widely seen as being transformational[47] and have already "changed the clean energy landscape faster" than expected.[48] To optimize the benefits of the IRA in supporting clean, reliable, and affordable electricity, utilities need to fully integrate those laws and their impacts into every facet of their resource planning; some guidance for doing so was recently released by RMI.[49] This is especially true for

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[46] U.S. Dept. of Energy, *Investing in American Energy* (Aug. 16, 2023), https://www.energy.gov/policy/articles/investing-american-energy-significant-impacts-inflation-reduction-act-and; RMI, *RMI's Guide to Federal Clean Energy Incentives*, https://rmi.org/rmis-guide-to-federal-clean-energy-incentives/ (last accessed Mar. 8, 2024).

[47] Blue Green Alliance, *A User Guide to the Inflation Reduction Act: How New Investments Will Deliver Good Jobs, Climate Action, and Health Benefits*, at 1, 4 (Oct. 13, 2022), https://www.bluegreenalliance.org/wp-content/uploads/2022/10/BGA-IRA-User-GuideFINAL-1.pdf

[48] Business Council for Sustainable Energy, *One Year Later: The Inflation Reduction Act is Driving the Clean Energy Transformation* (Aug. 16, 2023), https://bcse.org/one-year-later-inflation-reduction-act-is-driving-clean-energy-transformation/.

[49] RMI, *Planning to Harness the Inflation Reduction Act: A Toolkit for Regulators to Ensure Resource Plans Optimize Federal Funding* (Feb. 2024), https://rmi.org/wp-content/uploads/dlm_uploads/2024/02/planning_to_harness_the_inflation_reduction_act_a_toolkit_for_regulators_to_ensure_resource_plans_optimize_federal_funding.pdf.

rural electric co-ops, for which nearly $11 billion in grants, loans, and loan modifications to support rural clean energy development are included in the IRA.[50]

Big Rivers has taken a couple steps to incorporate the IRA into its resource planning. For example, the Company appears to have considered the IRA's significantly expanded and extended investment and production tax credits for solar, storage, and wind included in modeling those resources.[51] In addition, Big Rivers submitted a Letter of Interest to the U.S. Department of Agriculture's Rural Utilities Service ("RUS") seeking financial support under the IRA's Powering Affordable Clean Energy Program ("PACE") for a proposed 100 MW solar and 50 MW storage project.[52] The Joint Intervenors were happy to hear that Big Rivers has been invited to submit a full application for such financial support,[53] and are hopeful that this effort will lead to construction in Kentucky of a solar-storage project that is affordable for ratepayers.

Unfortunately, in other ways Big Rivers has fallen far short of fully pursuing the opportunities provided under the IRA and, as such, has largely missed a chance to improve affordability for residential and commercial ratepayers while advancing a reliable and cleaner energy system. As detailed in the EFG Report, one significant shortcoming in Big Rivers' DSM Market Potential Study ("MPS") was its complete failure to factor in the substantial amounts of IRA funding for energy efficiency that will be coming to Kentucky, which is one of the factors that caused the MPS to significantly underestimate the potential and overestimate the costs of

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[50] Rachel Frazin, *Rural Clean Energy to get $11 Billion Inflation Reduction Act Boost*, The Hill (May 16, 2023), https://thehill.com/policy/energy-environment/4006240-rural-clean-energy-to-get-11b-inflation-reduction-act-boost/; *see also* Evergreen Collaborative, *Next-Generation Rural Electrification: How Rural Electric Co-ops Can Repower America with the Inflation Reduction Act* (Aug. 2023), https://www.evergreenaction.com/policy-hub/How-Rural-Electric-Co-ops-Can-Repower-America-with-the-Inflation-Reduction-Act-August-2023.pdf.
[51] Big Rivers Response to Joint Intervenors Request No. 1-43.
[52] Big Rivers 2023 IRP at 56.
[53] Big Rivers Response to Joint Intervenors Request No. 1-12.

DSM programs for Big Rivers.[54] In addition, beyond a few short references to tax credits and grant programs, the IRP itself has no analysis of how Big Rivers could maximize the opportunities under the IRA. Data requests seeking analysis of opportunities under specific IRA programs similarly turned up nothing.[55]

Most significantly, with regards to the two largest sources of potential financial assistance in the IRA – the U.S. Department of Energy's Energy Infrastructure Reinvestment Program ("EIR") and the RUS's Empowering Rural America ("New ERA") program – Big Rivers has not sought any financial assistance under the former, and for the latter submitted only a flawed application for a $2.5 billion project that is very unlikely to save ratepayers any money.

Under the EIR program, utilities can obtain low-cost financing for projects that, among other things, "retool, repower, repurpose, or replace energy infrastructure that has ceased operations."[56] Potentially eligible projects include replacement or repurposing the sites of already retired power plants with renewable energy, storage, virtual power plants, and transmission interconnection to off-site clean energy.[57] A number of utilities throughout the country have sought financial assistance through the EIR program, and at least three state commissions have ordered utilities to report on how they are utilizing the EIR program.[58] Big Rivers, however, has not sought financing under the EIR program, with the only explanation

[54] EFG Report at 38-40.
[55] *See* Big Rivers Responses to Joint Intervenors Requests No. 1-12(a), 1-13(a).
[56] U.S. Dept. of Energy Loan Programs Office, *Energy Infrastructure Reinvestment*, https://www.energy.gov/lpo/energy-infrastructure-reinvestment (last accessed Mar. 8, 2024).
[57] *Id.*
[58] Christian Fong et al., *The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy*, RMI (Feb. 16, 2024), https://rmi.org/the-energy-infrastructure-reinvestment-program-federal-financing-for-an-equitable-clean-economy/.

offered being that the Company has "prioritized" potential opportunities supported under the PACE and New ERA programs.[59]

Under the New ERA program, the RUS has $9.7 billion in budget authority available to provide financial assistance for energy projects that would "achieve the greatest reduction in GHG emissions . . . in a way that promotes resiliency and reliability of rural electric systems and affordability for their members."[60] Such financial assistance can take the form of a grant worth up to 25% of the total eligible costs of the proposal, and either a 0% loan or a loan set at 2% or the Treasury rate.[61] Any single applicant cannot receive financial assistance exceeding 10% of the RUS's total budget authority for the program – i.e. $970 million.[62] In calculating the budget authority that a proposal would use, grants are counted on a dollar-to-dollar basis, while loans are counted on their "subsidy rate."[63] For fiscal year 2024, the New ERA program subsidy rates were 42.23% for 0% loans, and 19.30% for 2% or Treasury rate loans.[64] So, a $100 New ERA loan would use up $42.23 of budget authority if it were a 0% loan, or $19.30 of budget authority if it were a 2% or Treasury rate loan.[65]

RUS has identified a long list of types of projects that are eligible for such financial assistance, including renewable energy systems, zero-emission systems, energy storage, carbon capture and sequestration ("CCS"), microgrids and distributed energy strategies, transmission

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[59] Big Rivers Response to Joint Intervenors Request No. 1-14.
[60] RUS, *Notice of Funding Opportunity for the Empowering Rural America (New ERA) Program*, 88 Fed. Reg. 31,218, 31,219 (May 16, 2023).
[61] *Id.* at 31,222.
[62] *Id.* at 31,221.
[63] *Id.* at 31,222; *see also* U.S. Dep't of Agric., *Frequently Asked Questions: Empowering Rural America (New ERA) Program – Version 8.0*, at 27–29 (Sept. 12, 2023), https://www.rd.usda.gov/media/file/download/new-era-faqs-v8-09132023.pdf ("New ERA FAQ").
[64] New ERA FAQ at 29.
[65] *Id.*

improvements, and activities that will significantly reduce energy demand.[66] In addition, an eligible entity could request New ERA program support to modify existing RUS debt, or refinance debt from a third party, for a stranded asset, so long as the resulting savings are invested in an eligible GHG reduction project.[67] Either individual projects or a portfolio of such GHG reduction projects are eligible for funding.[68] Initial Letters of Interest ("LOI") to seek funding were due by September 15, 2023, and the response was overwhelming, with 157 proposals covering more than 750 clean energy projects in rural communities submitted.[69] Combined, the submittals sought more than double the $9.7 billion in funding that RUS has available under the New ERA program.[70] RUS is now reviewing those LOIs, upon which it will decide to which projects it will invite full applications.

Into this highly competitive process, Big Rivers submitted an LOI seeking financial assistance for a single project – installing CCS on the D.B. Wilson plant.[71] According to the LOI, the "total estimated capital cost" of such CCS project, which Big Rivers has named "Project Wildcat," would be $2.5 billion.[72] In the LOI, Big Rivers states that it seeks a 25% project grant of $630 million, and a 0% project loan to cover the remaining $1.89 billion of cost.[73]

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[66] 88 Fed. Reg. at 31,223.
[67] *Id.* at 31,222. The New ERA FAQ explains that the stranded assets for which debt modification or refinancing can be sought includes "previously closed fossil fuel plants," not just plants to be closed in the future. New ERA FAQ at 23–24, 37.
[68] *Id.*
[69] U.S. Dep't of Agric., *USDA Sees Record Demand to Advance Clean Energy in Rural America Through President Biden's Investing in America Agenda* (Sept. 27, 2023), https://www.usda.gov/media/press-releases/2023/09/27/usda-sees-record-demand-advance-clean-energy-rural-america-through.
[70] *Id.*
[71] Attachment 1 to Big Rivers Response to Joint Intervenors Request No. 1-13 ("New ERA LOI").
[72] New ERA LOI at 4.
[73] *Id.*

Big Rivers' decision to propose a single $2.5 billion CCS project for New ERA funding is questionable for a number of reasons. First, the LOI plainly fails to meet the eligibility requirements of the New ERA program as the amount of financial assistance requested greatly exceeds the $970 million per-applicant budget authority cap that Congress placed on the program. As explained above, the $1.89 billion 0% loan sought by Big Rivers would count at a 42.23% subsidy rate, which means it would use up $798 million in budget authority. When added to the $630 million grant, which counts on a dollar-to-dollar basis, Big Rivers' proposal would use up $1.428 billion in budget authority, or $458 million more than the $970 million cap. When asked in discovery how the LOI fits within the $970 million per-applicant cap, Big Rivers provided no explanation but instead simply claimed that "if Big Rivers is invited to apply, the application will fall below the $970 million maximum limit for a single borrower" and "cost estimates will be reevaluated and adjusted accordingly to move forward with the project."[74] It seems risky at best to assume that RUS, which is facing far more applications than it has budget authority to support, would invite an application based on an LOI that on its face does not satisfy a basic eligibility requirement for the program.[75]

Second, while affordability is a core element of whether a project is eligible for New ERA funding, Big Rivers' LOI states only that the $2.5 billion CCS project "could be cost neutral or slightly cost positive."[76] Even that claim appears quite optimistic given the amount of money involved and the preliminary nature of the cost estimates at issue. In addition, the "cost neutral or slightly cost positive" claim relies on Big Rivers receiving the full grant and 0% loan

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[74] Big Rivers Response to Joint Intervenors Request No. 2-56(a), (b).
[75] 88 Fed. Reg. at 31,224 (noting that the LOI should "include[ ] sufficient information to determine a pool of prospective Applicants which advance the goals of the statute, achieve policy objectives, meet minimum requirements, and are within the funds allocated to the program.")
[76] New ERA LOI at 4.

requested which, as shown above, significantly exceeds the $970 million in budget authority that any single applicant can utilize under the program. Furthermore, the claim relies on the assumption that Big Rivers would generate $165 million per year in IRS 45Q tax credits for capturing 1.84 million tons of CO2 every year.[77] That annual capture amount is presumably based on the assumption in the IRP that the CCS project would capture 90% of all CO2 emissions from the plant, but when asked for support for that assumption, Big Rivers stated only that the "carbon capture estimates are preliminary, based on current published research, and will be further evaluated . . . ."[78] Because the 45Q tax credit is based on a per ton of CO2 captured, if Big Rivers ended up capturing and sequestering significantly less than 1.84 million tons of CO2 per year from the Wilson plant, the amount of 45Q tax credit revenues received would be significantly lower than assumed.

Third, Big Rivers has provided no explanation for how it decided that it should seek New ERA funding for a $2.5 billion CCS project rather than any of the renewable energy, energy storage, distributed generation, demand reduction, microgrids, or debt refinancing options that are eligible for funding. When asked for any analysis or evaluation of potential funding opportunities under the New ERA program, Big Rivers responded that it "has no additional analysis to produce."[79] And when asked why it decided not to seek New ERA funding for any other types of eligible projects, Big Rivers simply asserted without support that the CCS project is an "excellent opportunity to strengthen its system" and is a project that is part of its strategic goals. While Big Rivers did model a scenario in its IRP in which Wilson is retrofit with CCS, as noted in the EFG Report[80] that scenario was never compared to one in which Wilson is instead

[77] *Id.*
[78] Big Rivers Response to Joint Intervenors Request No. 1-51(b).
[79] Big Rivers Response to Joint Intervenors Request No. 1-13(a).
[80] EFG Report at 18-19.

retired and replaced with new clean energy resources, so the modeling provides no support for Big Rivers' decision to pursue New ERA funding for retrofitting Wilson rather than new clean energy resources.

Fourth, the LOI is marred by other errors and inconsistencies. For example, the CCS capital cost assumed in Big Rivers IRP modeling is different than the $2.5 billion "total estimated capital cost" cited in the LOI. When asked about this discrepancy, Big Rivers said that the $2.5 billion figure was based on a study that purports to account for the "full costs of CCS" including "initial investment, financing, energy use . . . 'other' operating costs and distribution as well as injection costs."[81] It is not clear whether all of those costs would be eligible for financial support under the New ERA program, but, regardless, many of those costs are not "capital" costs and should not have been identified as such in the LOI. The LOI is also muddled as to how much CO2 would purportedly be captured at the Wilson plant, as it identifies an annual capture amount of 1.84 million tons per year on page 3, an annual GHG reduction of 1.94 million tons later on that same page, and then on page 10 states that "the project is projected to capture and sequester approximately 2.33 million tons of CO2 per year." What is clear is that the LOI claims an additional 392,082 tons of CO2 emissions "avoided" per year[82] apparently as the result of unidentified increased zero emissions energy supplies that are not part of the New ERA proposal,[83] and that the GHG reduction figures claimed in the application do not account for the impacts of the significant amount of generation that would be needed to power the CCS equipment.[84] This difference, sometimes referred to as the energy penalty or the parasitic load,

[81] Big Rivers Response to Joint Intervenors Request No. 2-56 and Attachment; 2-57.
[82] New ERA LOI at 4.
[83] Big Rivers Response to Joint Intervenors Request No. 2-58(a).
[84] Big Rivers Response to Joint Intervenors Request No. 2-58(b).

has been reported to be around 20% of a power plant's capacity.[85] In short, Big Rivers' New ERA LOI hardly qualifies as a meaningful effort to fully maximize the cost-saving and emission reduction opportunities provided by the IRA.

## VIII. BIG RIVERS HAS NOT ADEQUATELY ACCOUNTED FOR FUTURE ENVIRONMENTAL COMPLIANCE COSTS AND RISKS AT THE WILSON PLANT IN THIS IRP.

Big Rivers in its IRP notes that it

> necessarily devotes a significant amount of effort to the evaluation of existing and anticipated environmental regulations. Indeed, it may be impossible to overstate the influence of environmental regulation on the Company and its strategic assets, in particular the generation portfolio it has built and will build to serve its Members-Owners. In light of a complex and ever-evolving framework of state and federal rules, Big Rivers chooses each day to seek and act on the best available information, remaining focused on compliance and responsibility, reliability, and cost-effectiveness.[86]

Notwithstanding these assertions, however, Big Rivers has not included in its discussion or analysis a reasonable or complete accounting of all likely environmental compliance costs and risks facing the Wilson coal plant during the planning period. Rather, Big Rivers appears to have assumed that any environmental regulations that are either (1) proposed but not yet final, or (2) a final requirement but with compliance costs that are not yet certain, do not need to be considered for purposes of assessing the future costs of operating the Wilson coal plant. This is a patently unreasonable assumption that taints all of Big Rivers' modeling and provides another example of how Big Rivers has failed to account for the impact to ratepayers of its unexamined decision to continue operating Wilson until at least 2045. Whatever the cost of additional environmental

[85] Congressional Research Service, *Carbon Capture and Sequestration (CCS) in the United States*, at 2 (Oct. 5, 2022), https://crsreports.congress.gov/product/pdf/R/R44902/17.
[86] Big Rivers 2023 IRP at 91.

regulatory requirements facing the Wilson coal plant, it is not zero, and Big Rivers' decision to assume that it is effectively zero for planning purposes, for a number of environmental rules, makes its planning for this IRP unreasonable.

There are several environmental regulations that are likely to significantly increase environmental compliance costs at the Wilson plant that have been recently proposed by the U.S. Environmental Protection Agency ("EPA") and are projected to be finalized in the coming months. First, as Big Rivers acknowledges in the IRP,[87] on May 23, 2023, EPA published proposed new greenhouse gas ("GHG") emission limits and guidelines for new and existing coal and natural gas-fired power plants.[88] For existing coal plants such as Wilson, these proposed regulations would require compliance either through carbon capture and sequestration ("CCS") or retirement by date certain combined with other performance standards (including natural gas co-firing for some units). EPA has said that it anticipates finalizing these requirements in April 2024.[89] While EPA recently announced that existing gas plants will not be addressed in the current round of rulemaking, the forthcoming rule will set performance standards for existing coal plants.[90] According to Big Rivers, however, because there is a "lack of certainty" around the proposed rule, and despite acknowledging that the rule could have "exceptionally high costs

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[87] *Id.* at 92–95.
[88] EPA, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units*, 88 Fed. Reg. 33,240 (May 23, 2023).
[89] Office of Info. and Regul. Affairs, *NSPS for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs* (2023), https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2060-AV09.
[90] *See, e.g.*, Lisa Friedman, *E.P.A. to Exempt Existing Gas Plants From Tough New Rules, for Now*, N.Y. Times (Feb. 29, 2024), https://www.nytimes.com/2024/02/29/climate/epa-climate-power-plant-emissions.html.

of implementation,"[91] "Big Rivers has not conducted a formal analysis of the potential amount or timing of costs to comply with EPA's proposed greenhouse gas rule."[92]

Although Big Rivers did evaluate an "Aggressive Carbon Regulation" by modeling a scenario in which CCS was installed at Wilson in 2032,[93] as discussed above, the assumptions underlying that scenario – in particular, that federal grant, loan, and tax credit funding could render what Big Rivers identifies as a $2.5 billion project as "cost neutral or slightly cost positive"[94] – are unrealistic and speculative at best. Because this scenario was Big Rivers' only attempt to quantify and evaluate the likely costs and risks associated with compliance with greenhouse gas regulations at the Wilson coal plant over the planning period, Big Rivers has not done a reasonable or complete assessment of those costs and risks for this IRP.

The same is true for other EPA rules which have been proposed and are anticipated to be finalized in the coming months. In March 2023, EPA proposed supplemental revisions to the Effluent Limitations Guidelines and Standards ("ELG") rule for steam electric power plants.[95] This proposed regulation would, among other things, strengthen existing requirements for bottom ash and flue gas desulfurization wastewater, and set new discharge standards for combustion residual leachate and legacy wastewater.[96] EPA anticipates finalizing these revised ELG standards in April 2024.[97] Similar to the proposed greenhouse gas regulations, however, Big Rivers has not conducted any formal analysis of the potential additional costs and risks for

[91] Big Rivers 2023 IRP at 94.
[92] Big Rivers Response to Joint Intervenors Request No. 1-60(b).
[93] Big Rivers 2023 IRP at 144.
[94] Big Rivers Response to Joint Intervenors Request No. 1-13, Attachment No. 1 at 4.
[95] EPA, *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 88 Fed. Reg. 18,824 (Mar. 29, 2023).
[96] *Id.*
[97] Office of Info. and Regul. Affairs, *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2023), https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2040-AG23.

the Wilson coal plant associated with the supplemental ELG rule, despite the fact that this new rule will regulate additional waste streams that are not regulated under the current rule.[98] Nevertheless, Big Rivers did not address the supplemental ELG rule at all in its 2023 IRP.

Similarly, the Wilson coal plant may face additional costs and risks from EPA's revisions to the Coal Combustion Residuals ("CCR") rule. In May 2023, EPA proposed additional regulations for "legacy" CCR surface impoundments and management units, which had not previously been subject to federal requirements.[99] If adopted as proposed, this new EPA rule would include "requirements for groundwater monitoring, corrective action, closure, post-closure care, and recording and recordkeeping"[100] for these "legacy" CCR units, which the proposed rule defines to include not only impoundments but also any "non-containerized accumulation[s] of CCR . . . includ[ing] inactive CCR landfills and CCR units that closed prior to" the 2015 effective date of the CCR Rule.[101] Earlier, inactive phases of the Wilson plant's CCR landfill would thus likely be covered by this expansion of the CCR Rule, as would any other historic CCR disposal at the site that meet the rule's definition of a CCR management unit. Not only did Big Rivers not address this rulemaking at all in its 2023 IRP, the company refused to respond to any discovery concerning the rule's potential applicability at the Wilson site, asserting that it would be "premature and inappropriate" even to identify which portions of the Wilson site would be regulated under the new rule.[102] Once again, Big Rivers is assuming for planning purposes in this IRP that the costs of compliance with this rule at the Wilson coal plant will be zero, even though once finalized, the rule is likely to impose additional CCR cleanup and monitoring costs

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[98] Big Rivers Response to Joint Intervenors Request No. 1-57.
[99] EPA, *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments*, 88 Fed. Reg. 31,982 (May 18, 2023).
[100] *Id.* at 32,019.
[101] *Id.* at 32,034.
[102] Big Rivers Response to Joint Intervenors Request No. 1-59(a).

that will increase the cost of continuing to operate the Wilson coal plant throughout the planning period.

In addition, there are also at least two environmental regulations that have already been finalized, but for which Big Rivers unreasonably assumes Wilson will have zero compliance costs, because the exact timing and costs of compliance are not yet certain. First, Big Rivers asserts that it "has not conducted . . . any formal evaluation or analysis" of the potential compliance costs and risks to the Wilson coal plant from the Good Neighbor Plan, because this rule is currently stayed as to Kentucky pending national litigation over its implementation.[103] EPA had finalized the Good Neighbor Plan in June 2023 to address cross-state air pollution emissions resulting in non-attainment of 2015 ozone national ambient air quality standards ("NAAQS") in downwind states.[104]

Big Rivers' refusal to plan for the ultimate need to comply with the Good Neighbor Plan is in stark contrast to the position taken by Louisville Gas & Electric and Kentucky Utilities ("LGE&-KU") in their recent CPCN case before the Commission.[105] In its final order in that case, the Commission agreed with LG&E-KU that "while . . . the stay creates uncertainty as to the implementation of the Good Neighbor Plan, or similar standards based on the 2015 NAAQS, the Commission does conclude that the Good Neighbor Plan or a similar standard will ultimately be implemented in Kentucky."[106] Specifically, the Commission found that the legal challenges to the Good Neighbor Plan were procedural in nature and stated that "the Commission does not

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[103] Big Rivers Response to Joint Intervenors Request No. 1-58(b)–(d).

[104] *See* EPA, *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards*, 88 Fed. Reg. 36,654 (June 5, 2023).

[105] *See* Case No. 2022-00402, *In re: Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements* ("LG&E-KU CPCN Case").

[106] LG&E-KU CPCN Case, Nov. 6 2023 Order at 69–70.

think that it would be reasonable to conduct resource planning based on th[e] remote assumption" that an appeal to the U.S. Supreme Court might make the requirement for upwind states to reduce their nitrogen oxide emissions go away altogether.[107] This is exactly what Big Rivers did in its 2023 IRP, however – Big Rivers assumed that because the Good Neighbor Plan is in litigation, it need not consider the likely compliance costs and risks to the Wilson coal plant from that rule.[108] This "head in the sand" approach to resource planning is exactly the position that the Commission recently rejected in the LG&E-KU CPCN case, and Commission Staff should reject it with equal clarity here.

Another final environmental requirement for which Big Rivers unreasonably assumes zero future compliance costs is the 2015 CCR Rule's requirement that regulated CCR units such as the Wilson Phase II Landfill implement corrective action remedies to clean up groundwater that is found to be contaminated in excess of regulatory standards.[109] Big Rivers does not even mention in its 2023 IRP that it has unresolved compliance obligations at Wilson under the 2015 CCR Rule. As it conceded in response to discovery, however, groundwater monitoring at the Wilson Phase II Landfill has identified, since 2019, that there are Statistically Significant Increases of lithium and cobalt in downgradient groundwater monitoring wells.[110] Nevertheless, despite the fact that federal regulations require that a remedy be selected "as soon as feasible" and implemented "within a reasonable period of time,"[111] Big Rivers asserts that it is continuing to study the problem "so that it can effectively evaluate and develop a comprehensive remedy."[112] Thus, according to Big Rivers, "it would be premature to model any financial or

[107] *Id.* at 70–71.
[108] Big Rivers Response to Joint Intervenors Request No. 1-58(b)–(d).
[109] 40 C.F.R. §§ 257.93–257.98.
[110] Big Rivers Response to Joint Intervenors Request No. 2-31(a)–(b).
[111] 40 C.F.R. § 257.97(a), (d).
[112] Big Rivers Response to Joint Intervenors Request No. 2-31(c).

performance impacts in an IRP" of the need to address this ongoing compliance issue.[113] Big Rivers fails to explain, however, why it has not yet been feasible to identify a groundwater cleanup remedy four years after confirming exceedances from multiple contaminants, why additional monitoring data might be needed in order to do so, or how its failure to identify a remedy justifies Big Rivers' default assumption that the compliance cost would be zero. This is not a problem that Big Rivers can "study" forever and hope that it goes away; rather, this is another serious environmental compliance issue that Big Rivers has completely failed to assess as part of evaluating the impacts of a plan that simply takes the continued long-term operation of the Wilson plant as a given.

## IX. BIG RIVERS UNREASONABLY FAILED TO EVALUATE THE ECONOMICS OF, OR POTENTIAL RETIREMENT DATES FOR, THE WILSON PLANT.

A critical aspect of the IRP is Big Rivers' decision to continue operating the Wilson throughout the planning period and beyond. In reviewing an IRP, Staff have previously made clear that two of its primary goals are ensuring that such resource decisions have been adequately and fairly evaluated, and that critical data, assumptions, and methodologies underlying such a decision are documented and reasonable.[114] Those goals are not met here with regards to Wilson, however, as no analysis is presented in the IRP of the economics of such continued long-term operation of Wilson or of retiring and replacing the unit at some earlier date. Instead, continued operation of Wilson throughout the planning period was baked into the IRP as an unexamined and untested assumption.[115] Big Rivers did not model the economics of any earlier possible

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[113] *Id.*
[114] 2020 IRP Staff Report at 4.
[115] The IRP references an "expected retirement date" of 2045 for the Wilson plant. IRP at 35, Tbl. 2.3(c). But Big Rivers acknowledges that it did not analyze 2045 or any other retirement year in the IRP and,

retirement dates for the Wilson plant, nor did it run any scenarios in which the model was allowed to decide whether to retire Wilson, even after Staff specifically asked Big Rivers to do so.[116] Such a head-in-the-sand approach is unreasonable and demonstrates a failure to satisfy basic requirements of the IRP process.

In response to requests for information, Big Rivers offers various reasons for its unexamined and untested assumption of the long-term operation of Wilson, none of which hold water. First, Big Rivers contends that "[i]t is unlikely that the model would have chosen to retire the Wilson unit and replace it with an alternative if the model had been given the option,"[117] and further claims that the unit has a "demonstrated ability to produce economic . . . energy and capacity."[118] But the way to determine whether the model would have chosen to retire and replace the Wilson unit is, of course, to actually run such a scenario, not to merely speculate about the possible results. As for the "demonstrated ability" of Wilson to produce economic energy and capacity, when asked for "any profit and loss statement, revenue projection, net present value revenue requirement, or other economic analysis of the unit completed since 2018," Big Rivers produced nothing.[119] Instead, the Company simply referred to the 2023 IRP[120] which did not evaluate the economics of the continued operation or retirement and replacement

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instead, states that it selected 2045 to "to signify that Big Rivers expects Wilson to be operating throughout the Member-Owners' contract terms." Big Rivers Response to Joint Intervenors Request No. 2-13(b). The Company also claims that it "selected 2045 to comply with 807 KAR 5:058 Section 8(3)(b)(5)" of the IRP regulation. *Id*. But that regulatory provision simply requires the utility to identify all generating facilities that it plans to have in service during any of the fifteen years of the planning period. 807 KAR 5:058 Section 8(3)(b)(11) does require Big Rivers to identify any scheduled retirement dates for its generating units, but it is unclear from Big Rivers IRP and responses to requests for information whether 2045 is really a scheduled retirement date for the Wilson plant.

[116] Big Rivers Response to Staff Request No. 2-24(c).

[117] Big Rivers Response to Staff Request No. 1-14(c).

[118] Big Rivers Response to Joint Intervenors Request No. 2-18(d)(ii).

[119] Big Rivers Response to Joint Intervenors Request No.1-8(b).

[120] *Id.*

of the Wilson plant and, as explained in Section VII above, failed to adequately address future environmental compliance costs and risks facing the plant.

The closest that Big Rivers comes to addressing the economics of Wilson is noting that the unit "was dispatched economically throughout the study period in all scenarios studied in the 2023 IRP."[121] But that modeling shows that under Base Case conditions, Big Rivers' coal generation plummets from 3,093 GWh in each of 2023 and 2024 to only 1,140 GWh in 2026, less than 1,000 GWh per year in each of 2027 through 2031 and does not clear 2,000 GWh per year again until 2033,[122] which suggests a significant decline in the economic competitiveness of Wilson. It is also interesting to note that in 2018, Big Rivers committed Wilson into the MISO energy market as an "Economic" resource the large majority of the time when the unit was not on outage, which means that MISO decided, based on economics, whether the unit would operate.[123] In 2019 through 2022, however, Big Rivers committed Wilson as a "Must-Run" resource most or all of the time the unit was not on outage, which means that MISO had to run the unit at least at its minimum operating level, regardless of economics.[124] While not definitive, these results raise questions about the economics of the Wilson plant that should have been examined as part of the IRP process.

Big Rivers also points to the purported reliable nature of the Wilson plant as a reason for not even evaluating potential retirement dates for the unit.[125] The Company concedes, however, that Wilson experienced a more than 200 MW derate from December 19, 2022 to January 3, 2023, including during Winter Storm Elliott, and also tripped offline for 2.6 hours during that

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[121] Big Rivers Response to Joint Intervenors Request No. 2-13(a).
[122] Big Rivers 2023 IRP at 155.
[123] Big Rivers Response to Joint Intervenors Request No. 2-11.
[124] *Id.*
[125] Big Rivers Responses to Staff Request No. 2-24(a) and Joint Intervenors Request No. 2-18.

storm.[126] In addition, the Wilson unit was committed as on "Outage" approximately 30% of the time in both 2018 and 2022.[127]

Big Rivers also explains that it did not evaluate any Wilson retirement dates in the IRP because it has "no intention" of closing the plant[128] and claims that its planned long-term operation of the Wilson plant is supported by the enactment of KRS 278.264.[129] But evaluating the economics of the continued operation of Wilson as compared to retiring and replacing it does not conflict with Big Rivers' stated intent, it simply ensures that such intent has been meaningfully and transparently evaluated, rather than simply declared by fiat. And KRS 278.264 does not foreclose retirement of a fossil unit but, instead, merely creates a rebuttal presumption against such retirement. Certainly nothing in that statute forecloses the careful evaluation of resource decisions that are at the core of the IRP process.

Finally, the Company claims that there are numerous technical challenges to allowing the model to select an optimal retirement date for a generating unit.[130] This claim is thoroughly refuted in the EFG Report,[131] which explains that utilities regularly evaluate the economics of a possible unit retirement by either letting the model select the economically optimal retirement year or by testing different potential retirement dates as inputs into the model. Big Rivers should have done the same with regards to Wilson in this IRP.

[126] Big Rivers Response to Joint Intervenors Request No. 1-6(a), (b).
[127] Big Rivers Response to Joint Intervenors Request No. 2-11.
Big Rivers Response to Joint Intervenors Request No. 2-11.
[128] Big Rivers Responses to Joint Intervenors Request No. 2-18(d)(ii) and Staff Request No. 2-24(c).
[129] Big Rivers Response to Staff Request No. 1-7.
[130] Big Rivers Response to Staff Request No. 2-24.
[131] EFG Report at 16-18.

## X. BIG RIVERS' 2023 IRP PROJECTS SIGNIFICANTLY MORE GENERATION AND CAPACITY THAN APPEARS TO BE NEEDED WITHOUT FULLY EVALUATING REASONABLE ALTERNATIVE OUTCOMES AND OPTIONS.

In the Company's IRP, the significant gaps between (1) projected total generation and total system energy requirements and (2) total system capacity and non-coincident peak demand suggest that Big Rivers is planning to build or maintain significantly more generation than it needs to serve its total "native system" load. Instead, Big Rivers appears to be assuming that new and/or renewed non-member sales contracts will materialize after the current ones will end between 2026 and 2029, and relies as well on the unexplored assumption that Direct Serve customer energy sales will remain at their 2024 level through 2042. These assumptions present significant risks to Big Rivers' members; thus, the Company should explain the significant gaps in these projections and adequately evaluate alternative scenarios where non-member and Direct Serve sales are lower or less profitable than assumed in the current load forecast. In addition, Big Rivers should demonstrate that any assumed new or renewed non-member sales contracts would be necessary and provide a net benefit to its members.

Big Rivers' IRP projects significantly more generation and capacity than appears to be needed. In the IRP, Big Rivers projects total system energy requirements increasing to approximately 6,800 GWh in 2026, but then falling to between 4,700 and 4,900 GWh per year from 2030 through 2042.[132] Big Rivers, however, projects total generation of approximately 6,500 GWh in 2030, 7,900 GWh by 2033, and nearly 9,000 GWh by 2042.[133] When comparing the data summarizing total generation and total system energy requirements, there is an approximately 2,000 GWh gap in 2030 that increases to over 3,500 GWh in 2037. There is a similarly significant gap between total system capacity and non-coincident peak demand starting

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[132] *See* Big Rivers 2023 IRP, Appendix A at A-47.
[133] *See* Big Rivers 2023 IRP, Tbl. 7.4.1(c) at 155.

in 2029. As a result of several non-member sales contracts terminating by 2029, Big Rivers will be losing approximately 345 MW of peak demand[134], bringing non-coincident peak demand down from approximately 1,200 MW in 2025 to under 900 MW in 2029 through 2042.[135] However, if Big Rivers retires the Green Station and constructs the new 635 MW NGCC in 2029 as proposed in the IRP[136], the Company's total power capacity would increase to 1,295 MW, which would result in nearly 400 MW of excess capacity.[137]

As discussed further in the EFG Report, Big Rivers' plan to build or maintain excess generation and capacity presents several risks to the Company's members, including fuel price risk exposure due to projected generation primarily consisting of coal and gas generating resources.[138] Big Rivers is obligated to develop an IRP that meets "future demand with an adequate and reliable supply of electricity at *the lowest possible cost for all customers*."[139] Thus, it is in the best interest of Big Rivers' members that the Company further evaluates reasonable alternative outcomes and options, as discussed below.

### A. Big Rivers should provide a complete energy forecast for the Company's Direct Serve class.

Big Rivers' Direct Serve customer sales are projected to increase from 28.8% of Big Rivers' native system sales in 2022 to between approximately 47 and 48% of native system sales between the years 2024 and 2042.[140] However, Big Rivers did not fully forecast the Direct Serve class the way it did other customer classes, such as the residential and general commercial and

[134] *Id.*, Appendix A at A-50.
[135] *Id.*, Appendix A at A-51.
[136] Big Rivers 2023 IRP at 140.
[137] *See id.* at 18, 140 (retiring the Green Station (454 MW) and constructing a new 635 MW NGCC would increase total capacity from 1,114 MW to 1,295 MW).
[138] EFG Report at 22-24.
[139] 807 KAR 5:058 (emphasis added).
[140] Big Rivers 2023 IRP, Appendix A at A-43–44; Big Rivers' Response to Joint Intervenors' Request No. 1-22.

industrial classes. Instead, Big Rivers simply assumed that the forecasted values for Direct Serve customers will stay steady between the years 2024 and 2042.[141] Although Big Rivers reasons that the Direct Serve class "contains a small number of customers that are far less likely to have their operations influenced by regional demographic, economic, and climate conditions relative to the rate classes that are econometrically modeled,"[142] the class is projected to be nearly half of the Company's total energy demand for close to two decades. This amounts to over 2,220 GWh of annual energy sales.[143] Simply assuming that nearly half of the Company's sales will remain constant for this significant period of time without adequately evaluating alternative outcomes presents significant risks to Big Rivers' members. As such, Big Rivers should, at a minimum, provide a complete forecast for the Direct Serve class as the Company did for other classes, such as the residential and general commercial and industrial classes, and test scenarios in which such sales are lower or higher than assumed.

### B. Big Rivers should evaluate whether the renewal or extensions of non-member sales contracts will be both necessary and beneficial to its members.

In 2012, Big Rivers began taking steps to mitigate the effects of the expected loss of over two-thirds of the Company's peak load due to the termination of contracts with two aluminum smelters in August 2013 and January 2014.[144] One of these steps called for Big Rivers to "evaluate options to execute forward bilateral sales agreements with counterparties, enter into wholesale power contracts, and/or participate in capacity markets to find load replacement for

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[141] Big Rivers Response to Joint Intervenors Request No. 1-19(b).
[142] *Id.*
[143] *See* Big Rivers 2023 IRP, Appendix A, at A-34.
[144] Case No. 2014-00166, *In the matter of 2014 Integrated Resource Plan of Big Rivers Electric Corporation*, Big Rivers Electric Corporation 2014 Integrated Resource Plan at 8 (Ky. P.S.C. May 15, 2014), https://psc.ky.gov/pscscf/2014%20cases/2014-00166/20140515_Big%20Rivers%20Electric%20Corporation_2014%20Integrated%20Resource%20Plan%20and%20Petition.pdf.

the load previously consumed by the smelters."[145] Big Rivers ultimately entered into several long-term, non-member sales contracts with Nebraska entities, Kentucky Municipal Energy Agency ("KyMEA"), [146] and Owensboro Municipal Utilities ("OMU"). [147]

The Company's contracts with the Nebraska entities and OMU are set to terminate in December 2026[148] while the contract with KyMEA is set to terminate in May 2029.[149] Although Big Rivers has informed the Nebraska entities that the Company will not renew those contracts,[150] Big Rivers has started discussions with OMU about contract renewal[151] and [redacted] As for KyMEA, Big Rivers stated that it will have discussions about contract renewal "closer to the end of the current

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[145] *Id.* at 37.
[146] Case No. 2017-00384, *In the matter of 2017 Integrated Resource Plan of Big Rivers Electric Corporation*, Big Rivers Electric Corporation 2017 Integrated Resource Plan at 61 (Ky. P.S.C. Sept. 21, 2017), https://psc.ky.gov/pscscf/2017%20cases/2017-00384/20170921_Big%20Rivers%20Electric%20Corporation%20Application.pdf.
[147] Big Rivers 2023 IRP, Appendix A at A-45.
[148] *See* Big Rivers Response to Staff Request No. 1-8(c); Market Based Rate Partial and Full Requirements Agreement Dated as of December 20, 2013 By and Among Big Rivers Electric Corporation and City of Wayne, Nebraska, at 6 (Sept. 10, 2014), https://psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/Contracts/City%20of%20Wayne,%20Nebraska/2015-07-21_Market%20Based%20Rate%20Partial%20and%20Full%20Requirements%20Agreement.pdf; Market Based Rate Partial and Full Requirements Agreement Dated as of December 31, 2013 By and Among Big Rivers Electric Corporation and City of Wakefield, Nebraska, at 6 (Sept. 10, 2014), https://psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/Contracts/City%20of%20Wakefield,%20Nebraska/2015-07-21_Market%20Based%20Rate%20Partial%20and%20Full%20Requirements%20Agreement.pdf.
[149] Agreement for the Purchase and Sale of Firm Capacity and Energy Between Big Rivers Electric Corporation and the Kentucky Municipal Energy Agency, at 7 (dated July 13, 2016), https://psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/Contracts/Kentucky%20Municipal%20Energy%20Agency/2016-12-12_Agreement%20for%20the%20Purchase%20and%20Sale%20of%20Firm%20Capicity%20and%20Energy.pdf.
[150] Big Rivers Response to Joint Intervenors Request No. 1-24(e).
[151] Big Rivers Response to Joint Intervenors Request No. 1-24(d).
[152] Big Rivers Response to Joint Intervenors Request No. 2-27.

contract term."[153] Although Big Rivers intends to pursue contracts renewals, renewals or extensions of the OMU or KyMEA contracts "were not modeled in the IRP because, at the time of the IRP's preparation, the likelihood of such extensions (as well as their provisions) were not known with sufficient clarity to warrant inclusion."[154]

Although Big Rivers did not model renewals or extensions of non-member sales contracts in the IRP, it appears that the Company is building or maintaining generation and capacity at least partially on the assumption that the OMU and KyMEA contracts will be renewed and/or that other non-member sales contracts will materialize. As noted above, Big Rivers is projecting total system energy requirements to decrease to between 4,700 and 4,900 GWh per year in 2030 and thereafter due to the termination of the aforementioned non-member sales contracts in the late 2020s.[155] Big Rivers, however, is projecting approximately 2,000 GWh of excess generation in 2030 that increases to over 3,500 GWh in 2037. The Company is similarly projecting nearly 400 MW of excess capacity once the non-member sales contracts terminate and if the new NGCC proposed in the IRP is constructed in 2029. Further, Big Rivers is not only potentially planning to build or maintain generation on the assumption of renewing non-member sale contracts, but the Company is also [redacted][156] Finally, it is worth noting that even if the OMU and KyMEA contracts are renewed or extended, there will still be excess capacity and generation starting in the early 2030s, partially because Big Rivers has confirmed that the contracts with the Nebraska entities will not be renewed.

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[153] Big Rivers Response to Joint Intervenors Request No. 1-24(d).
[154] Big Rivers Response to Joint Intervenors Request No. 2-28.
[155] *See* Big Rivers 2023 IRP, Appendix A at A-47.
[156] *See* Confidential Attach. 1 to Big Rivers' Response to Joint Intervenors' Request No. 1-23 [redacted]

Not only does this approach present significant risks to the Company's members, but Big Rivers has also failed to demonstrate that renewing or extending non-member sales contracts, apparently to support the construction of significant new generation capacity, would provide a net benefit to its members. In regard to the Company's non-member energy sales, Big Rivers states that it "engages in buying or selling any available excess resources where those transactions derive value for the Big Rivers members."[157] However, Big Rivers has failed to explain how embarking on a strategy of new and renewed non-member sales contracts and significant new generation to serve them, would "derive value" for its members. In response to a discovery request from Joint Intervenors asking Big Rivers to provide any analysis or calculation showing that its non-member energy sales to date have derived value for its members, the Company provided the actual and forecasted gross margin analyses for its non-member sales contracts for years 2018 through 2037.[158] In response to Joint Intervenors' request for net margin data, Big Rivers stated that it "does not conduct net margin analysis for Non-Member customer contracts."[159] A net margin analysis is critical for evaluating how profitable Big Rivers' non-member sales contracts are because it would not only provide the revenues earned from the sales, but it would also provide the costs of maintaining or building new generation needed to provide those sales. Thus, it is unclear just how beneficial, if at all, Big Rivers' non-member contracts are or will be for its actual members.

Building or maintaining generation on the assumptions of renewing non-member sale contracts and substantial Direct Serve sales remaining constant without evaluating reasonable alternative outcomes and options presents significant risks to Big Rivers' members. For these

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[157] *See* Big Rivers 2023 IRP, Appendix A at A-45.
[158] *See* Confidential Attach. 1 to Big Rivers' Response to Joint Intervenors Request No. 1-23.
[159] Big Rivers Response to Joint Intervenors Request No. 2-26(a), (b).

reasons, the Commission should require Big Rivers to explain the significant gaps between (1) projected total generation and total system energy requirements and (2) total system capacity and non-coincident peak demand in the Company's IRP. In addition, Big Rivers should provide a complete forecast for the Direct Serve class as the Company did for other classes, such as the residential and general commercial and industrial classes. Finally, since circumstances have changed and the Company is now in a much different situation than it was when it lost over two-thirds of its peak load, Big Rivers should evaluate whether the renewal or extensions of non-member sales contracts will be both necessary and provide a net benefit to its members.

## XI. CONCLUSION

Joint Intervenors appreciate this opportunity to provide initial comments and recommendations related to Big Rivers' 2023 Integrated Resource Plan and look forward to future opportunities for constructive dialogue concerning Big Rivers' planning efforts.

Respectfully submitted,

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## CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID*-19, this is to certify that the electronic filing was submitted to the Commission on March 8, 2024; that the documents in this electronic filing are a true representations of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

Byron L. Gary

Exhibit 1

EFG Report-Public Redacted Version


# Report on Big Rivers Electric 2023 Integrated Resource Plan

By: Chelsea Hotaling, Energy Futures Group
Dan Mellinger, Energy Futures Group

On behalf of Kentucky Resources Council and Kentuckians for the Commonwealth

March 8, 2024

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# 1. SUMMARY AND INTRODUCTION

Energy Futures Group ("EFG") was asked by Kentuckians for the Commonwealth and Kentucky Resources Council to perform a review of Big Rivers Electric Corporation's 2023 Integrated Resource Plan ("IRP").[1] The review was performed by Chelsea Hotaling, Consultant, and Dan Mellinger, Principal.[2] EFG is a clean energy consulting company focused on integrated resource planning as well as design, implementation, and evaluation of programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG has performed IRP modeling and critically reviewed IRPs in over a dozen states, provinces, and territories. Our work in these jurisdictions involves either conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms including EnCompass, which was used by Big Rivers and its consultant for this IRP.

Our feedback and recommendations throughout this report are intended to show how Big Rivers can enhance future IRP processes and filings. Our recommendations are discussed in detail in the body of the report. The following presents a high-level summary of our recommendations around the IRP:

**Stakeholder Process**

- Facilitate IRP stakeholder meetings and provide stakeholders with a schedule of when modeling and supporting data will be shared;
- Build time into the schedule to allow stakeholders to submit feedback on information shared and for Big Rivers to incorporate that feedback before the filing deadline;
- Schedule follow up meetings as necessary to discuss feedback that results in points of disagreement; and
- Assist stakeholders with obtaining an EnCompass project-based license, or provide stakeholders with a project-based license, to allow interested intervenors the ability to perform their own modeling runs in the same software package(s).

**IRP Inputs and Modeling**

- Relax supply side resource constraints to allow the model to have the option to select a portfolio of renewable, battery storage, and/or capacity purchases to replace the Green units in 2029.
- Allow battery storage resources to be selected within the model starting in 2027.
- Model battery storage resources at longer durations than four hours.

[1] Big Rivers 2023 Integrated Resource Plan, Case No. 2023-00310 (Sept. 29, 2023) ("Big Rivers 2023 IRP").
[2] The résumés of Chelsea Hotaling and Dan Mellinger are attached hereto as Exhibit A.

- Evaluate a higher capacity factor for new solar resources.
- Provide supporting information for the development of the BREC CC costs.
- Model higher capital costs for the BREC CC.
- Expand the evaluation of unit retirements to include several dates for the Green units and Wilson.
- Develop a distributed generation forecast with growth rates in line with historical averages.
- Energy efficiency resources should be evaluated as forced in resources to test the impact on expansion and dispatch results if the resource is not selected in the capacity expansion step.
- Evaluate the impact that off-system sales revenue has on the selection of the BREC CC through the application of market sales limits.

**DSM Market Potential Study ("MPS") Development**

- The MPS should include a comprehensive list of measures, including emerging technologies. Qualitative screening of measures should only occur based on fuel type matching to the utility.
- Technical potential should be based on a comprehensive list of measures, and the availability factor should be based on current, comprehensive, and geographically relevant research.
- Economic screening should consider a wider range of benefits, including avoided T&D, resiliency, and funding available through federal programs such as the Inflation Reduction Act ("IRA").
- Program factor and financial barrier adjustments in Achievable Potential should not apply when incentives are modeled at 100%.
- Program Potential should be established using reasonable incentive levels with a savings-optimized portfolio of measures, without an arbitrary budget cap.
- Funding available through the IRA should be included in the calculations of cost-effectiveness and adoption rate for relevant measures.
- Measure assumptions should be based on the most current available TRM or other reference sources from geographically similar jurisdictions.

# 2. STAKEHOLDER PROCESS

While Kentucky's IRP rules do not contain a specific requirement for utilities to hold stakeholder meetings leading up to the filing of the IRP, we recommend that Big Rivers facilitate stakeholder workshops for future IRP filings. For example, for its 2022 IRP, Kentucky Power held two stakeholder meetings that Joint Intervenor representatives and other interested groups were able to attend.[3] By contrast, when asked about engagement with stakeholders, Big Rivers indicated that engagement happens regularly with the three Member-Owners and that upon filing of the 2023 IRP, a Notice of Filing was published in newspapers in circulation with Big Rivers' service area.[4] By limiting stakeholder engagement to only these steps, Big Rivers has lost the opportunity to engage stakeholders on the development of the IRP inputs and scenarios and to allowing such stakeholders to provide feedback on that information before the modeling is completed and the IRP is filed.

The recommendations we put forth in this section are based on EFG's experience participating in stakeholder processes in many different jurisdictions across North America. These recommendations are intended to help Big Rivers further enhance the stakeholder process to foster collaboration and transparency, which will in turn lead to a more robust IRP process.

IRPs are not a set of discrete tasks that one can repeat and perfect, but rather are a process that must evolve with changes in circumstances, technology improvements, consumer preferences, policy requirements, etc. It is crucial for IRPs to have a stakeholder process in which stakeholder feedback is solicited and considered for incorporation into the IRP process. Figure 1 below shows a graphic of what we believe are the three pillars – transparency, collaboration, and implementation – that are necessary components of an IRP stakeholder process.

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[3] Kentucky Power 2022 Integrated Resource Plan, Volume A – Public Version, Case No. 2023-00092, at 17–18 (Mar. 20, 2023) ("Kentucky Power 2022 IRP"). Kentucky Power held the first stakeholder meeting on July 14, 2022, to discuss inputs and market scenarios, and the second meeting was held on January 25, 2023, where modeling results were presented to stakeholders.

[4] Big Rivers response to Joint Intervenors data request 1-56.

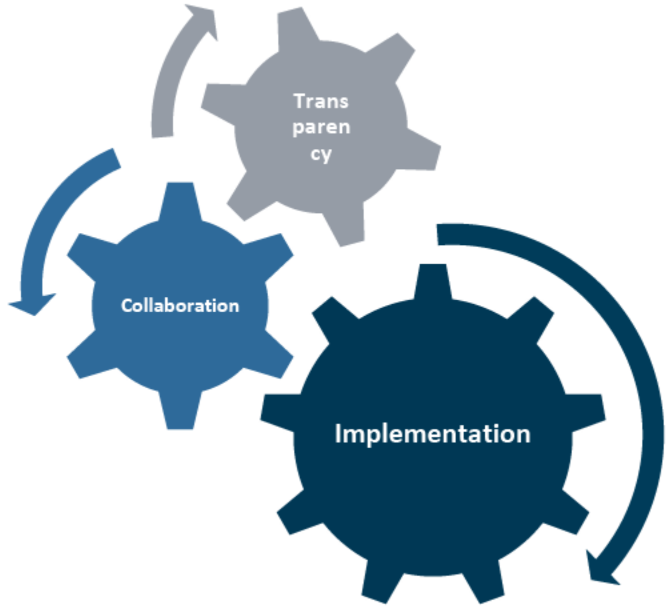


***Figure 1. Three Pillars for IRP Stakeholder Process***

For transparency and collaboration, we have found that the most transparent IRP processes include the following elements:

1. A process that allows for the sharing of modeling data[5] with stakeholders who sign a nondisclosure agreement ("NDA") to receive access to that information, while the IRP is still in development (and not merely after it is filed in the docket of a formal proceeding);
2. A schedule that outlines when modeling data will be released during the stakeholder process and by when feedback needs to be submitted;
3. A timeline that allows for stakeholders to review modeling data and provide feedback with enough time for that feedback to be incorporated into the IRP before it is finalized; and
4. Discussions between the utility and stakeholders on feedback and any potential points of disagreement.

One of the biggest barriers to a transparent and collaborative IRP process is not allowing stakeholders the opportunity to see modeling inputs or outputs prior to the filing of an IRP. When this occurs, there is no opportunity to include stakeholder input on the IRP– stakeholders can merely react to the final IRP and hope that their feedback is incorporated in

[5] Modeling data such as load forecast inputs, demand side management inputs, costs and operational parameters for new and existing resources, commodity price forecasts, and the modeling input and output files.

the next IRP potentially years down the road. Alternatively, when there is a process of stakeholder workshops, and the provision of modeling files and supporting data to stakeholders, this means that stakeholders can be active and thorough participants. Furthermore, if time is built into the schedule for stakeholder feedback, this increases the opportunity for stakeholder feedback to be incorporated in the IRP modeling.

AES Indiana[6] implemented this approach of sharing modeling inputs and outputs with stakeholders and soliciting feedback for its last two IRPs and we found that it significantly improved the stakeholder process. Table 1 below provides an example of a timeline that a utility could share with stakeholders for the release of information.

***Table 1. Example of Timeline to Release Information***

| Meeting | Topic |
|---|---|
| Meeting One | Load forecast<br>Demand Side Management inputs |
| Meeting Two | New resource costs and operating characteristics |
| Meeting Three | Portfolio Scorecard Metrics<br>Preliminary results |
| Meeting Four | Preferred Plan Selection |

Incorporating time into the schedule for stakeholders to submit feedback helps ensure that stakeholders have the opportunity to provide information and express their viewpoints all the way throughout the stakeholder process. While we recognize that the goal is not to produce an IRP entirely shaped by stakeholder input and there will likely still be disagreement between the stakeholder and the utility, the process allows the option to evaluate those differences. For example, if stakeholders and the utility feel that different resource costs ought to be used, two modeling runs using those different costs can be conducted. That opportunity is typically foreclosed once the IRP is filed. Allowing for feedback and holding meetings where all parties involved can express their opinion also helps to build trust and foster collaboration where it may not have occurred before.

Further transparency can be incorporated into these processes by obtaining project-based licenses on behalf of stakeholders which permit Commission Staff and intervenors to be able to conduct their own modeling runs in the same software package as the utility, typically at a lower price than if the stakeholders had to purchase a modeling license on their own (which many stakeholders could not afford to do). For example, KU and LG&E assisted the Joint

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[6] *See 2022 Integrated Resource Plan (IRP)*, AES Indiana (Dec. 1, 2022), https://www.aesindiana.com/integrated-resource-plan ("AES Indiana 2022 IRP").

Intervenors with obtaining a license to run the PLEXOS model in the CPCN proceeding that was completed in Fall 2023 (Case No. 2022-00402).

When all three pillars work together, this will help to ensure that an IRP can be shaped by stakeholders in important and meaningful ways, which is the objective of a stakeholder process. We offer the following recommendations to enhance the IRP process to achieve higher levels of transparency and collaboration:

1. Provide stakeholders with a schedule of when modeling and supporting data will be shared;
2. Build time into the schedule to allow stakeholders to submit feedback on information shared;
3. Schedule follow up meetings as necessary to discuss feedback that results in points of disagreement; and
4. Assist stakeholders with obtaining an EnCompass project-based license, or providing stakeholders with a project-based license, to allow interested intervenors the ability to perform their own modeling runs in the same software package(s).

# 3. INTEGRATED RESOURCE PLAN

The following sections are organized around the supply side resource inputs for the IRP modeling, including resource constraints, costs, accreditation, and unit retirements.

## 3.1. SUPPLY SIDE RESOURCE CONSTRAINTS

For its IRP, Big Rivers applied three constraints to potential new supply side resources: the date in which the model can first select the new resource, an annual limit on how much the model can select in any given year, and a cumulative limit on how much the model can select over the entire planning period. For instance, for four-hour battery storage resources, Big Rivers allowed the model to select the resource starting in 2029, applied an annual build limit of 300 MW, and a total cumulative build limit of 600 MW.[7]

Our first concern with the constraints applied to new resources is that 2029 is a critical point in time for the model as that is when the model can select new resources to replace the Green units if the model chooses to retire those units in 2029. In terms of the capacity needed to replace the Green units, from a winter accreditation standpoint, Green 1 is [redacted] MW and Green 2 is [redacted] MW for a total of [redacted] MW.[8] Based on the constraints that Big Rivers implemented for solar, wind, and four-hour battery storage, the model is not able to add enough replacement capacity for the Green units because of the build limits applied. This means that the model cannot even consider the option of replacing the Green units with a combination of renewables and storage. Table 2 below shows the annual build limits modeled for solar, wind, and four-hour battery storage resources between 2027 – 2029 and how much the winter capacity value of those resources. Based on the build limits modeled by Big Rivers, the model can only select up to 326 MW of resources from a winter accreditation standpoint by the 2029 retirement of Green. This is not enough to fully replace the Green units' capacity. It is also important to note that the model could not select any capacity purchases to cover any shortfalls in 2029.[9]

***Table 2. Renewables and Storage***

| **Nameplate (MW)** | **2027** | **2028** | **2029** | **Total** |
|---|---|---|---|---|
| Solar | 200 | 200 | 200 | 600 |
| Wind | 0 | 200 | 200 | 400 |
| Battery Storage, 4-Hour | 0 | 0 | 300 | 300 |
| | | | | |
| **Winter Accreditation (MW)** | | | | |
| Solar | 2 | 2 | 2 | 6 |

[7] Big Rivers 2023 IRP, Table 7.2.1 (a) at 135 and Table 7.2.1 (b) at 136.

[8] Big Rivers supplemental response to Joint Intervenors data request 1-1, Simulation Output Validation Workbook named "Base_SEN0_EE_8760," tab "Resource Monthly."

[9] Big Rivers response to Joint Intervenors data request 2-47.

| | | | | |
|---|---|---|---|---|
| Wind | 0 | 28 | 28 | 56 |
| Battery Storage, 4-Hour | 0 | 0 | 264 | 264 |
| **Total Winter Accreditation** | **2** | **30** | **294** | **326** |

In order to evaluate whether the model would have selected standalone battery storage, or a combination of renewables and battery storage to replace the Green units, Big Rivers should have evaluated either allowing battery storage to be selected starting in 2027 or allowing for a higher amount to be selected in 2029. In addition, the results from the All-Source RFP indicated that battery storage projects with [redacted] were included in Big River's shortlisted bids. However, for this IRP, Big Rivers did not model any storage resources with durations longer than four hours. We will discuss the RFP results in more detail in the following subsection.

In a discovery response, Big Rivers indicated a stance that "Big Rivers does not consider battery storage a generation resource that will complement intermittent renewable resources. Big Rivers believes resources which make available resilient dispatchable energy best complement intermittent renewable resources."[10] To the extent that this stance limited Big Rivers' willingness to fully consider storage resources in this IRP, we would note that it is misguided as renewables and battery storage added in combination do offer synergistic benefits that complement one another. Not only can battery storage resources be charged from excess renewable generation and then discharged during peak hours, but battery storage resources also offer additional benefits including energy arbitrage, capacity value, and ancillary services. Big Rivers did acknowledge that these additional value streams from battery storage resources can benefit customers.[11]

## 3.2. STANDALONE STORAGE RFP BIDS

Table 3 below shows the standalone battery storage resources that made Big Rivers' shortlist of bids that it received. It is not clear what criteria Big Rivers used to determine which bids made it to the shortlist, or how many total builds were received for the 2022 RFP. Of the shortlisted bids for standalone battery storage, [redacted][12] We did not have access to the specific bids provided in the RFP and are basing the indication that Big Rivers received bids [redacted] on the maximum capacity and storage capacity provided by Big Rivers. Not having access to the specific project bids also precludes us from understanding what assumptions around tax credits were assumed in the bids. Responses to the RFP were

[10] Big Rivers response to Joint Intervenors data request 2-61(b).
[11] Big Rivers response to the Office of the Attorney General data request 1-11(a).
[12] Big Rivers supplemental response to Joint Intervenors data request 1-9. Workbook named "RFP Shortlisted Proposal Summary". Storage durations were inferred from information on maximum capacity and storage capacity that were provided in the response.

due prior to the passage of the Inflation Reduction Act and it is likely that the bids did not reflect those tax credits.

***Table 3. Battery Storage Shortlist Bids***[13]

| Maximum Capacity (MW) | Storage Capacity (MWh) | Duration (Hours) | Commercial Operating Date | Tolling Price ($/kW-Yr) |
|---|---|---|---|---|
| [redacted] | | | | |

Big Rivers only modeled four-hour battery storage resources in EnCompass. However, based on [redacted] there are opportunities for longer duration battery storage resources to be considered and could have been modeled in EnCompass.

### 3.3. RENEWABLE COSTS AND SOLAR CAPACITY FACTOR

For battery storage resource costs, Big Rivers reported that it used capital costs from the 2022 AEO technology assessment developed by the EIA and then applied the NREL ATB conservative cost curve to develop the costs for the entire planning period.[14] Big Rivers took a different approach to model the capital costs for wind and solar:

> *Because the IRP calculations were developed at a time when the NREL database [did not] reflect a period of market volatility related to post-COVID supply chain issues, solar capital cost curves were developed using market intelligence based on recent market offers known during the assumptions development period and implemented in conjunction with the approach described in subpart a.*[15]

The capital cost starting point for new wind and solar resources is a hardcoded value in the workbook provided in response to Joint Intervenors 2-35.[16] The starting capital cost for both solar and wind is [redacted] the AEO technology assessment and the NREL ATB, but it is unclear if Big Rivers adjusted this value to reflect bids received in the 2022 All-Source RFP or

[13] Big Rivers supplemental response to Joint Intervenors data request 1-9, Workbook named "RFP Shortlisted Proposal Summary".
[14] Big Rivers response to Joint Intervenors data request 2-14 (a).
[15] Big Rivers response to Joint Intervenors data request 2-14 (b).
[16] Big Rivers response to Joint Intervenors data request 2-35, Workbook named "JI 2-35 CONFIDENTIAL Attachment".

other market information. If the starting capital costs rely on the market information from the All-Source RFP, it is also not clear if Big Rivers contacted bidders to inquire about updates to the bid price. The All-Source RFP conducted by Big Rivers was issued on April 1, 2022, with proposals due by June 1, 2022.[17] The timing of the RFP also was in the midst of significant market volatility, especially for solar resources. The RFP was also conducted prior to the passage of the IRA and therefore the bids likely do not include either the investment tax credit ("ITC") or the production tax credit ("PTC") for the solar and battery storage resources. This could have implications for the cost of the bids provided in response to the RFP.

When modeling renewable resources in capacity expansion and production cost modeling, the resources are typically assigned an 8,760 hourly shape to represent their anticipated energy production. Based on the information provided by Big Rivers, one hourly shape was modeled for the upcoming solar project (referred to as "Unbridled Solar") and has a higher capacity factor compared to the capacity factor modeled for the generic new solar additions. Table 4 below shows the monthly capacity factor comparison between the Unbridled Solar facility and the PACE Solar project, which was the same shape applied to the new generic solar resources in EnCompass.

***Table 4. Monthly Capacity Factor (%) Comparison***[18]

| Month | Unbridled Solar | PACE Solar |
|---|---|---|
| 1 | [redacted] | [redacted] |
| 2 | [redacted] | [redacted] |
| 3 | [redacted] | [redacted] |
| 4 | [redacted] | [redacted] |
| 5 | [redacted] | [redacted] |
| 6 | [redacted] | [redacted] |
| 7 | [redacted] | [redacted] |
| 8 | [redacted] | [redacted] |
| 9 | [redacted] | [redacted] |
| 10 | [redacted] | [redacted] |
| 11 | [redacted] | [redacted] |
| 12 | [redacted] | [redacted] |

It is expected that solar resources located in different locations will have differences in energy production, and therefore the resulting capacity factor. This would have implications for the energy availability and levelized cost of a project if the costs are spread over a lower amount of generation. Table 5 below shows a comparison of the capacity factor modeled in capacity expansion and production modeling for Big Rivers in comparison to Kentucky Power, KU/LG&E, in addition to a few utilities in Indiana that are also located in MISO Zone 6.

[17] Big Rivers response to Commission Staff data request 2-32(b).
[18] Big Rivers response to the Office of the Attorney General data request 2-9.

*Table 5. Capacity Factor Comparison for Solar*[19]

| Utility | Capacity Factor Modeled (%) |
|---|---|
| BREC New Solar | 21%[20] |
| BREC Unbridled Solar | [redacted] |
| Kentucky Power IRP | 23%[21] |
| KU/LG&E IRP | 25.1%[22] |
| AES Indiana IRP | 24.5%[23] |
| CenterPoint Energy IRP | 25.2%[24] |
| Duke Energy Indiana IRP Refresh | 24%[25] |

Based on what other utilities in Kentucky and utilities located within MIZO Zone 6 are modeling for the capacity factor, Big Rivers' assumption seems to be on the low end.

## 3.4. BREC COMBINED CYCLE ("BREC CC") COSTS

One of the supply side resources that EnCompass was able to select starting in 2029 is a 635 MW NGCC ("Natural Gas Combined Cycle Gas Turbine"), which Big Rivers refers to as the "BREC CC" in the IRP. When asked about the source of the capital costs for the BREC CC, Big Rivers said "The values in both the 'IRP Input Tables' tab of the 'Master Assumptions Workbook' and Table 7.1.4(j) were the inputs used for the 'BREC CC' and were based on Big Rivers' detailed estimate of the cost to construct the combined cycle project on the Green site."[26] It is not clear if the "detailed estimate" is referring to a feed or other engineering base

[19] NIPSCO discussed an analysis in its 2021 IRP where historical weather years between 2007 through 2019 produced an average capacity factor for solar in the mid 20% range for a representative solar resource. *Northern Indiana Public Service Company LLC: 2021 Integrated Resource Plan*, NIPSCO, at 200 (Nov. 15, 2021), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf.

[20] Big Rivers response to Joint Intervenors data request 2-34; Big Rivers 2023 IRP, Table 7.1.4(g).

[21] Kentucky Power Company, *Integrated Resource Planning Report to the Kentucky Public Service Commission*, at 96 (Mar. 20, 2023), https://psc.ky.gov/pscecf/2023-00092/sebishop%40aep.com/03202023030104/KPCO_2022_IRP_Volume_A-Public.pdf ("Kentucky Power 2022 IRP").

[22] Case No. 2021-00393, *In the matter of Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Louisville Gas & Electric Company and Kentucky Utilities Company 2021 Integrated Resource Plan, Vol. I, Table 5-16 at 5-40 (Ky. P.S.C. Oct. 19, 2021).

[23] AES Indiana 2022 Integrated Resource Plan (IRP), Vol. 1 at 71 (Dec. 1, 2022), https://www.aesindiana.com/sites/default/files/2022-12/AES-Indiana-2022-IRP-Volume-I.pdf.

[24] CenterPoint Energy 2022/2023 IRP, Attachment 1.2 CEI South Technology Assessment Summary Table, at page 40 of 1123 (May 2023), https://midwest.centerpointenergy.com/assets/downloads/planning/irp/2022-2023%20IRP%20-%20Volume%202%20of%202.pdf.

[25] Charles River Associates, *Duke Energy Indiana 2022 CPCN Information Sharing Session 1*, Slide at 39 (Oct. 21, 2022), https://www.duke-energy.com/-/media/pdfs/our-company/dei-irp-information-sharing-session-1.pdf.

[26] Big Rivers response to Joint Intervenors data request 2-52(b).

exercise or are simply more of a screening level estimate. Big Rivers did not provide any further support for the development of the [redacted]/kW[27] capital cost. It is also important to note that costs were developed for a generic CC, without reference to a specific location like the BREC CC, and the capital cost reported in the workbook provided by Big Rivers is [redacted]kW.[28] Big Rivers stated that "The Generic CC was not modeled as a resource alternative in the EnCompass model, but the costs were based on publicly available data."[29]

Since the start of the pandemic, there have been very few new combined cycle projects that have come far enough along in development to have produced more than a screening level cost estimate. One exception is Entergy's 1,215 MW Orange County Advanced Power Station ("OCAPS"). As of October 2022, the estimated cost of that facility (excluding hydrogen co-firing capability) was $1,419,160,000 or about $1,168 per kW in 2026 nominal dollars. The capital cost that Big Rivers is modeling for the BREC CC is [redacted] for a plant half the size of OCAPs. This suggests that Big Rivers' cost estimate is materially understated as per kW costs and size of a plant tend to be inversely correlated. In addition, EFG has seen significant competition for turbines, engineering services, and labor, which have led to project delays and cost increases. Big Rivers has also acknowledged that there are supply chain risks associated with the BREC CC.[30]

Another consideration for the cost of the BREC CC is that the costs of transmission interconnection are unknown. Big Rivers did not model transmission interconnection costs for supply-side resources[31] and Transmission system upgrades have not been identified for the proposed BREC CC.[32] According to Big Rivers, "The proposed NGCC is expected to be located on Big Rivers' property adjacent to the existing Green Generating Station in Henderson County."[33] It will be important to evaluate the proposed BREC CC in light of any transmission system cost upgrades against other resources as the total capacity for the Green units is 454 MW which is less than the 635 MW of the proposed BREC CC. It is possible that there may be transmission impacts even just due to the size difference of these resources.

## 3.5. MISO SEASONAL CONSTRUCT

MISO shifted from an annual to a seasonal resource adequacy construct in the fall of 2022. At the time of the modeling for this IRP, the proposed methodology for accrediting thermal resources was based on a Seasonal Accredited Capacity ("SAC") values where unit

[27] *See* Big Rivers response to Joint Intervenors data request 2-36, Workbook "JI 2-36 CONFIDENTIAL Attachment".
[28] Big Rivers supplemental response to Joint Intervenors data request 1-1, Workbook "BREC IRP Master Assumptions Workbook", worksheet "Alt_Capital&FixedOM".
[29] Big Rivers response to Joint Intervenors data request 2-45.
[30] Big Rivers response to Joint Intervenors data request 2-62(b).
[31] Big Rivers response to Joint Intervenors data request 2-40.
[32] Big Rivers response to Joint Intervenors data request 2-40(b).
[33] Big Rivers response to Joint Intervenors data request 2-40(c).

performance was evaluated during the tightest hours.[34] However, as MISO has been working on determining the seasonal accreditation approach, there have been modifications to the approach proposed for both renewables and storage in addition to thermal resources. At its Resource Adequacy Subcommittee[35] ("RASC") meeting[36] held on January 17, 2024, MISO discussed additional changes to its proposed methodology which is also known as the Direct Loss of Load ("DLOL") approach. Under DLOL, MISO would first model generator performance in its LOLE model to determine the amount of each resource type that is available during loss of load hours. That capacity value would then be allocated to generators based on their 3-year historical performance during the modeled loss of load and tight margin hours. MISO is anticipating it will implement the DLOL methodology for the 2028/2029 planning year.

Table 6 below shows the DLOL accreditation values for resource classes in the columns labeled "Proposed". While we understand that this information was provided by MISO after the development of Big River's IRP, it does have implications for the accredited value of the supply side resources considered in the capacity expansion modeling.

***Table 6. MISO DLOL Accreditation***[37]

| Resource Class | Summer | | Fall | | Winter | | Spring | |
|---|---|---|---|---|---|---|---|---|
| | DLOL | | DLOL | | DLOL | | DLOL | |
| | Base | Proposed | Base | Proposed | Base | Proposed | Base | Proposed |
| Gas | 88% | 88% | 88% | 88% | 66% | 66% | 68% | 69% |
| Combined Cycle | 90% | 90% | 88% | 89% | 74% | 74% | 74% | 75% |
| Coal | 91% | 91% | 87% | 88% | 72% | 73% | 74% | 74% |
| Hydro | 96% | 96% | 97% | 96% | 92% | 92% | 88% | 88% |
| Nuclear | 90% | 90% | 83% | 85% | 84% | 86% | 77% | 80% |
| Pumped Storage | 98% | 98% | 98% | 98% | 47% | 50% | 70% | 67% |
| Storage | 94% | 94% | 89% | 93% | 90% | 91% | 97% | 95% |
| Solar | 36% | 36% | 28% | 31% | 0% | 2% | 15% | 18% |
| Wind | 11% | 11% | 15% | 15% | 13% | 16% | 16% | 16% |
| Run-of-River | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

Table 7 below shows a comparison between the MISO "Proposed" accreditation values as compared to what was modeled by Big Rivers in the IRP for the BREC CC, battery storage, wind, and solar resources. MISO's change to the DLOL approach for resource accreditation has the largest impact on the winter accreditation for the BREC CC as it was modeled with an [redacted]% capacity value in the winter as compared to the MISO "Proposed" accreditation of 74%.

[34] Big Rivers 2023 IRP at 58.

[35] This is the modeling MISO undertakes each year to develop the planning reserve margins.

[36] MISO RASC Meeting. *Market Redefinition: Accreditation Reform*. Retrieved from https://cdn.misoenergy.org/20240117%20RASC%20Item%2007a%20Accreditation%20Presentation%20(RASC-2020-4%20and%202019-2631379.pdf.

[37] *Id.* at 11.

*Table 7. Seasonal Accreditation Comparison*

| | Summer | | Fall | | Winter | | Spring | |
|---|---|---|---|---|---|---|---|---|
| | Modeled | Proposed | Modeled | Proposed | Modeled | Proposed | Modeled | Proposed |
| BREC CC[38] | [redacted] | 90% | [redacted] | 89% | [redacted] | 74% | [redacted] | 75% |
| Storage | | 94% | | 93% | | 91% | | 95% |
| Wind | | 11% | | 15% | | 16% | | 16% |
| Solar | | 36% | | 31% | | 2% | | 18% |

## 3.6. EVALUATING UNIT RETIREMENTS

For the Green units, Big Rivers modeled the decision of continuing to operate the Green units with a life extension until 2043 or retire them in 2029. For the Wilson plant, Big Rivers did not present any modeling runs in this IRP in which it is retired, nor did Big Rivers allow the model the option to retire the plant in any year. This means that all plans assume the operations of the Wilson plant through 2050.

In response to discovery questions submitted by Commission Staff on the ability to evaluate an optimized retirement date over the planning period, Big Rivers indicated several complications with this approach:

> 1. *Annual capital expenditures associated with retirement in each calendar year were not available*[39] *and developing those projections is a laborious and time-consuming undertaking.*[40]
>
> 2. *Providing the model with the opportunity to retire a unit(s) in any year creates significant data and computational challenges with limited value in this case.*[41]
>
> 3. *It is infeasible to model a potential replacement for the Reid unit and/or the Wilson unit at this time. Big Rivers' efforts to develop the 2023 IRP involved many months of examination and discussion by and among various departments and disciplines, both internal and external to Big Rivers. Not only would the requested additional modeling require the unrealistic assumption that Big Rivers would or could replace such a significant portion of its power supply, it would require a complete re-tooling of the entire EnCompass model, as well as a resetting of multiple, fundamental, baseline assumptions including (but not limited to) geographical considerations associated with potential power supply locations, transmission impacts, potential retirement costs, and other necessary capital expenditures, operational changes, generation*

[38] Big Rivers supplemental response to Joint Intervenors data request 1-1. Values reported in "Master Assumptions Workbook", worksheet "Alt_SAC".

[39] Big Rivers response to Commission Staff data request 1-14(a).

[40] Big Rivers response to Commission Staff data request 1-53(a).

[41] Big Rivers response to Commission Staff data request 1-26(b).

*resource reliability and diversity considerations, market risk, and potential stranded assets. There are significant data and computational challenges associated with altering such fundamental assumptions, and any efforts to do so at this stage would undoubtedly suffer from the extensive data-gathering and related work that informs the year-long process of preparing an integrated resource plan*.[42]

We acknowledge that in some instances, it can be challenging to optimize unit retirement dates because of the difficulties in representing dynamic schedules of projected capital expenditures that adjust to each retirement date. In some instances, model run time considerations may also come into play. Despite these challenges, there are ways to address these concerns and evaluate different retirement dates. If the concern is that the projected capital expenditures will have significant differences depending on the retirement date, expenditures can be determined for several points in time over the planning period, such as 2030, 2035, or 2040. Those can be input into the model and EnCompass can see the different retirement options with the corresponding capital expenditures. Another option is to not allow EnCompass to choose retirement dates within the capacity expansion modeling, and set specific retirement dates that go in as an input into the model. It appears that Big Rivers did acknowledge value in studying retirement options at discrete points in time, but caveated those to "changes in environmental regulations or major maintenance milestones." [43]

In terms of the labor and time needed to create these inputs, this concern speaks to the importance of the decisions made at the outset and beginning stages of the IRP development. If Big Rivers had held an IRP stakeholder workshop, it is possible that stakeholder feedback would have elevated this issue and allowed it to be incorporated into the IRP modeling in time for the filing.

Big Rivers did include in the IRP what it defined as an "Aggressive Carbon Reduction" portfolio, prompted by EPA's proposed greenhouse gas regulations. [44] For this scenario, however, consideration was only given to Wilson and the BREC CC having CCS installed in 2032. In order to have a more complete view of the options around this potential future greenhouse gas rule, Big Rivers should have compared the costs to continue to operate Wilson with the addition of CCS with a portfolio that does not pursue the CCS pathway and instead retires the Wilson plant.

The retirement of the Wilson plant should be evaluated in future IRPs, whether for the near-term action window or later in the planning period. Comparing the continued operations of existing resources with investment in new resources is the hallmark of IRP planning. It would be imprudent to not continuously evaluate the economics of all resources. In addition, many of the concerns that Big Rivers listed in response to the Commission Staff discovery question including transmission impacts, potential retirement costs, other necessary capital

[42] Big Rivers response to Commission Staff data request 2-24(c).
[43] Big Rivers response to Commission Staff data request 2-30(a).
[44] Big Rivers 2023 IRP at 144.

expenditures, and operational changes, are all items that we typically see utilities evaluate and include in their IRP modeling

We would also recommend a similar viewpoint for the evaluation of the retirement of the Green units. The modeling performed for this IRP evaluated two options: either retiring Green in 2029 or allowing it to operate through 2043. Modeling the retirement of the Green units in this manner does not allow for a scenario where the Green units may operate for a few years past 2029, but would retire before 2043. It is possible that this would have been a more economic option in comparison to operating the units until 2043, as the projected costs for the units see an increase in projected costs in 2039 and 2040.[45]

## 3.7. CARBON CAPTURE AND SEQUESTRATION ("CCS")

Figure 2 below shows a comparison of the annual generation from the BREC CC (green lines) and the Wilson plant (blue lines) with and without the installation of CCS. The installation of the CCS changes the operations of the units, and results in a lower output, higher heat rate, and higher operational costs.[46] In 2044, the generation from the BREC CC significantly drops from the levels observed between 2032 -2043, while the Wilson plant does not dispatch after 2043. The pivotal point for the units is 2044 because that is when the tax credits associated with the CCS expire. Upon the expiration of those tax credits, the costs of operating the resources (fuel and variable O&M) are no longer offset with the tax credits and the cost to operate the resources increases, resulting in Wilson not dispatching economically.[47] This underscores the risk of the economics of the resources being dependent on qualifying for the tax credits.

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[45] Big Rivers supplemental response to Joint Intervenors data request 1-1. Values reported in "Master Assumptions Workbook", worksheet "FOM".

[46] Big Rivers response to the Office of the Attorney General data request 2-2(e).

[47] Big Rivers response to Commission Staff data request 1-55(a).

[redacted]

*Figure 2. Dispatch of the BREC CC and Wilson with CCS*[48]

## 3.8. NATURAL GAS PRICE SENSITIVITIES

In the IRP, Big Rivers discusses the development of a low and high natural gas price forecast that are modeled as sensitivities.[49] Upon review of the EnCompass modeling files, we could not find evidence that the natural gas price forecast was modeled at different values from the base forecast. After notifying Big Rivers, it was confirmed that the high and low gas price sensitivity runs in EnCompass inadvertently excluded the modification to the natural gas price forecast under each sensitivity. It is our understanding that Big Rivers intends to file updated results and produce corrected modeling files for those sensitivities.

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[48] Big Rivers supplemental response to Joint Intervenors data request 1-1, Simulation Output Validation Workbook named "S2_SEN0_EE_8760", tab named "Resource Annual."

[49] Big Rivers 2023 IRP at 139.

## 3.9. DISTRIBUTED GENERATION FORECAST

For the distributed generation forecast, Big Rivers developed a forecast based on the Energy Information Administration Annual Energy Outlook. Table 8 below shows the average annual growth rates on a historical basis for the past five years, and the projections of average annual growth from the forecast for the next 5, 10, and 20 years. The projected growth rates are significantly different in comparison to the average annual growth rates from the previous 5 years.

***Table 8. Average Annual Growth Rates (%) for Distributed Generation***[50]

| | Residential Energy | Commercial Energy |
|---|---|---|
| Previous 5 Years | 58.64% | 59.06% |
| Next 5 Years | 7.87% | 8.57% |
| Next 10 Years | 6.98% | 6.16% |
| Next 20 Years | 6.36% | 4.79% |

We recommend that the distributed generation forecast reflect a closer alignment to the historical growth rates for distributed generation. This could be through modification to the base forecast or developing an additional forecast to model as a sensitivity.

## 3.10. MODELING ENERGY EFFICIENCY AS A SUPPLY SIDE RESOURCE

In the 2020 IRP, Big Rivers did not model Demand Side Management ("DSM") resources:

> *DSM programs were not modeled as a supply-side resource in the PLEXOS model because the DSM programs provide small load reductions (e.g., 1-2 MWs). These low (1-2 MWs) load reductions would not change the PLEXOS model's overall results. The DSM programs should be evaluated on their own merit, including whether the programs provide financial benefit to Big Rivers' Member-Owners.*[51]

For this IRP, the energy efficiency resource evaluated has a starting capacity of approximately 2 MW in 2024 and grows to approximately 17 MW by 2033. It is possible that the model did not select the energy efficiency resource because it is not large enough to offset a new build resource, but it is also possible that it is falling in the Mixed

[50] *Id.*, Appendix A at A-20.
[51] Case No. 2020-00299, *In the Matter of Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation*, Response to Commission Staff's Request 1-28 (Ky. P.S.C. Mar. 19, 2021).

Integer Programming (“MIP”) Gap of the model. In capacity expansion models that involve optimizations using MIP, like EnCompass, the model will go through a process to determine how to round units (either up or down) and will continue to search until it reaches a point where the difference, or gap, between the costs of the current solution and the optimal solution is within a certain percentage. This percentage threshold is set by the MIP Gap setting in the model. This means that there could be more than one solution that is within the MIP Gap setting. It is possible that an expansion plan with and without the energy efficiency resource could have solutions with costs that are within the MIP Gap.

The other factor that may have influenced the model’s failure to select the energy efficiency resource is that the resource was set up to be modeled in a way where it could only be selected in 2024 and no other year in the planning period.[52] Instead of only allowing for the resource to be selected in one year, Big Rivers could allow the model to see energy efficiency resources throughout several periods of time in the planning period, such as 2024–2029, 2030–2036, 2037–2042.

Even if the selection of the energy efficiency resource cannot be attributed to these factors, we would recommend that the value of energy efficiency be further evaluated by forcing the selection of the resource. Taking this step allows for the evaluation of the impact of energy efficiency on the expansion plan and its costs, in addition to the dispatch of Big Rivers’ other resources. Even if the limited energy efficiency resource tested by Big Rivers is not large enough to offset the build of a new supply side resource, it may offset generation from thermal resources and could avoid fuel costs and reduce emissions. These avoided costs could lower the system costs of plans that include the energy efficiency resource.

[52] Big Rivers supplemental response to Joint Intervenors data request 1-1, EnCompass model file named “ProjectConstr_IRP_Base_EE”, worksheet named “TimeSeriesDatedChanges_ProjCons”. For the Time Series named “BREC_DSM AM”, the value of 1 is only reported for 2024.

# 4. RISKS WITH THE PREFERRED PLAN

After reviewing Big Rivers' preferred plan, which includes the addition of the 635 MW BREC CC in 2029, there are several risks around the seasonal capacity position and the reliance on market sales. Furthermore, there are also environmental risks around the operation of the BREC CC.

The retirement of the Green units and the replacement with the BREC CC puts Big Rivers in a position of significant excess capacity across all seasons in addition to a position involving large amounts of off-system sales. Figure 3 below shows Big Rivers' planning reserve margin in 2030[53] in comparison to the seasonal planning reserve margin released by MISO for the 2024/2025 planning year.[54] On a MW basis, this translates to a surplus of [redacted] MW for the summer, [redacted] MW for the fall, [redacted] MW for the winter, and [redacted] MW for the spring when evaluating Big Rivers capacity position in 2030 against the MISO planning reserve margins for the 2024/2025 planning year.

[redacted]

***Figure 3. Big Rivers Reserve Margin in 2030***

The second risk with the preferred plan is the volume of off-system sales once the BREC CC comes online in 2029. Figure 4 below shows the annual generation by resource type for Big Rivers in comparison to the annual energy requirements across the planning between 2030 – 2050. With the addition of the BREC CC, the preferred plan relies on a significant level of

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[53] Big Rivers supplemental response to Joint Intervenors data request 1-1. Simulation Output Validation Workbook named "Base_SEN0_EE_8760," tab "Resource Monthly."

[54] Retrieved from Planning Year 2024-2025 Loss of Load Expectation Study Report MISO — Resource Adequacy, MISO, at 36 (Dec. 5, 2023), https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf

generation in excess of what is needed to meet the annual energy requirements. This results in the BREC CC operating at an average capacity factor of [redacted]%[55] under the base case conditions.

[redacted]

***Figure 4. Big Rivers Generation vs. Energy Requirements (GWh)***

One of the reasons that there is such a high level of off-system sales is that Big Rivers did not place any constraints on the interchange of power with MISO. As Big Rivers stated, "The EnCompass model was developed to mimic the actual interactions between MISO and Big Rivers. The model was configured to allow for all of Big Rivers' load energy to be purchased from the MISO market, and all of its generation or potential generation energy to be sold to the MISO market."[56] Big Rivers also stated that any excess generation "[...] would presumably be utilized by other load serving entities in MISO." [57] The objective of capacity expansion models is to minimize overall system costs, and market revenue associated with off-system sales offsets those system costs. Since the model seeks to minimize system costs and has no limit on the amount of sales, energy market revenue can easily become a major influence on which new resources the model selects. This is a common modeling challenge in IRP

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[55] Big Rivers supplemental response to Joint Intervenors data request 1-1, Simulation Output Validation Workbook named "Base_SEN0_EE_8760", tabs named "Resource Annual" and "Company Annual."
[56] Big Rivers response to Joint Intervenors data request 2-47.
[57] Big Rivers response to Joint Intervenors data request 1-53(c).

modeling. It's very difficult to adjust the market price forecast such that on-system resources are not over or under dispatched. As a result, it would be important to test the impact of modeling constraints on the amount of total off-system sales allowed per year. Big Rivers highlighted this when they said "While the model had the option to replace the Green units with other resource types, *when factoring in the market energy value*, the model found the replacement of 454 MW of out-of-market generation with 635MW of fuel-efficient generation to be the least cost option."[58] If the very high level of off-system sales is the primary reason that the model is adding the BREC CC, the ability to sustain this projected level of off-system sales and resulting revenues in actual operations would also be very important to shielding customers from unnecessary rate impacts. If the market prices end up being lower than forecasted in the modeling, and/or if the natural gas prices are higher, then that would change the energy market value and operational costs for the BREC CC.

In addition to the risk of the plan relying too heavily on off-system sales, the plan also means the majority of the Big Rivers generation is concentrated in coal and natural gas generating resources. In 2030, the projected percent of generation from coal and natural gas resources is [redacted]. This introduces fuel price risk exposure to ratepayers. For example, Big Rivers' IRP projects an increase in coal pricing at the Wilson unit that is expected to help lead to a significant decline in generation from Wilson through 2029.[59] Fuel costs are passed through to customers, which means that customers bear the entire risk from volatile fuel prices. In a discovery response related to the question of execution risk associated particularly with solar resources, Big Rivers said "Big Rivers embraces a balanced generating portfolio that does not lean too heavily on any one resource type."[60] The projected generation from the resources in Big Rivers' preferred portfolio indicate that Big Rivers will be leaning heavily on coal and natural gas generation.

The selection of the BREC CC also faces environmental regulatory risks. On May 23, 2023, the Environmental Protection Agency ("EPA") EPA published proposed new greenhouse gas ("GHG") emission limits and guidelines for existing coal and new gas-fired power plants.[61] Specifically, EPA proposed standards for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion Electric Generating Units ("EGUs") based on hydrogen co-firing and carbon capture and sequestration ("CCS"), and is simultaneously proposing to establish new emission guidelines for existing coal-fired steam EGUs that reflect the application of CCS and the availability of natural gas co-firing.[62] On May 23, 2023, the

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[58] Big Rivers response to Commission Staff data request 1-36 (emphasis added).
[59] Big Rivers response to Commission Staff data request 1-23.
[60] Big Rivers response to the Office of the Attorney General data request 1-9.
[61] *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (May 23, 2023).
[62] *Id.* at 33,243. While the proposed GHG rules also included guidelines for the largest, most frequently operated existing stationary gas combustion turbines based on hydrogen co-firing and CCS, EPA recently announced that it is dropping existing gas turbines from the final GHG rules that are expected to be issued in April 2024 and, instead, will

proposed new GHG rules were published in the Federal Register. EPA has announced the intention to finalize the proposed new GHG rules by April 2024 after considering the comments submitted this summer.[63]

For new or reconstructed natural gas simple cycle turbines with an intermediate-load capacity factor of 20-50%, only the use of "lower emitting fuels," e.g., natural gas and distillate oil, with a standard of performance of 1,150 lb $CO_2$ per MWh would be required while such units that operate at more than a 50% capacity factor would need to meet emission limits that are based on the blending of 30% low-GHG hydrogen starting in 2032.[64] One of the compliance pathways will be operating units with a capacity factor limit of 50% starting in 2032. Big Rivers did evaluate the impact of installing CCS on the BREC CC starting in 2032 under the Aggressive Carbon Reduction portfolio. However, if the compliance pathway is to limit the operations of the BREC CC to a 50% annual capacity factor limit, that would have implications for the projected costs of the Preferred Portfolio, given the significant level of off-system sales.

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work to develop a "'new, comprehensive approach' to cover the 'entire fleet of natural gas-fired turbines.'" S. Patel, Power Magazine, EPA Drops Existing Gas-Fired Plants from Contentious Power Plant GHG Rule (March 7, 2024), https://www.powermag.com/epa-drops-existing-gas-fired-plants-from-contentious-power-plant-ghg-rule/

[63] Office of Info. & Reg. Affairs, *Spring 2023 Unified Regulatory Agenda, View Rule: NSPS for GHG Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; Emission Guidelines for GHG Emissions From Existing Fossil Fuel-Fired EGUs; and Repeal of the ACE Rule* (2023), https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2060-AV09.

[64] *See* EPA, Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation24.pdf (accessed February 26, 2024) (Table on slide 8, summarizing the proposed new GHG NSPS for new natural gas EGUs and Table on slide 13, summarizing the proposed new GHG rule for existing EGUs).

# 5. MARKET POTENTIAL STUDY ("MPS")

Big Rivers engaged Clearspring Energy Advisors ("Clearspring") in 2023 to determine the energy and demand savings potential that could be achieved through demand-side management ("DSM") programs. [65] The market potential study quantified the technical, economic, achievable, and program potential savings for the years 2024-2033.[66] The MPS core objective was to "identify potential cost-effective demand-side opportunities that can directly and verifiably reduce demand for, and consumption of, electricity over a period covering 2024-2033."[67]

A market potential study is intended to serve multiple use cases, including the following as identified by the American Council for an Energy-Efficient Economy ("ACEEE").[68]

- Provide the analytic basis for efforts to treat energy efficiency as a resource equivalent to supply-side resources.
- Quantify the energy efficiency resource for system planning.
- Identify and prioritize market sectors and energy-efficient technologies that offer the highest resource opportunities.
- Inform the development of utility savings targets.
- Determine appropriate and adequate funding levels for delivering energy efficiency programs.

EFG has identified numerous issues and concerns with the Clearspring MPS, which are summarized below and discussed in detail later in this report. Cumulatively, these issues result in an MPS that identifies a low estimate of energy savings potential and a higher-than-expected cost. As a result, energy efficiency was an underrepresented and disadvantaged resource that was not adequately considered within the Big Rivers IRP.

1. **MPS Measure List**: The MPS failed to consider the potential benefits from a more comprehensive list of DSM measures.
2. **Qualitative Screening**: Measures were eliminated from the MPS subjectively, using a "qualitative screening" analysis prior to the quantitative economic analysis of cost-effectiveness.

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[65] Appendix B to the Big Rivers Electric Corporation 2023 Integrated Resource Plan (filed Sept 29, 2023) ("Big Rivers MPS"). Joshua Hoyt and Katherine Steward of Clearspring Energy Advisors, LLC prepared the document entitled as "Demand-Side Management Potential Study, Big Rivers Electric Corporation, Henderson, Kentucky".
[66] Big Rivers MPS §1.2.
[67] *Id.* at 1-2.
[68] Max Neubauer, *Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies. Available*, ACEEE at 3 (Aug. 2014), https://www.aceee.org/sites/default/files/pdfs/u1407.pdf ("Cracking the TEAPOT").

3. **Technical Potential**: The Technical Potential was limited by the measure list and assumptions regarding availability.
4. **Economic Potential**: The MPS failed to adequately consider the benefits and costs, resulting in an unusually large loss of savings during the economic screen.
5. **Achievable Potential**: The calculation of achievable potential includes inappropriate adjustments for the participant cost test and other financial barriers.
6. **Program Potential**: The size of the Program Potential scenario is arbitrary, and the portfolio was not optimized for cost and savings.
7. **Inflation Reduction Act**: The MPS failed to consider the influence of the Inflation Reduction Act on incentives and measure adoption.
8. **MPS Reference Sources**: The MPS used multiple outdated reference sources.

## 5.1. MPS MEASURE LIST

The Big Rivers MPS included an analysis of 180 unique measures, consisting of 65 residential and 115 non-residential measures.[69] The 180 measures analyzed by Clearspring pales in comparison to other geographically similar electric-only market potential studies. As shown in Table 9 and Figure 5, Clearspring analyzed roughly half of the measures compared to the next closest MPS, CenterPoint Indiana (356 unique measures). Compared to the most comprehensive studies, Clearspring analyzed 38% of the measures in the Consumers Energy MPS (471 unique measures) and 32% of the measures in the Ameren Missouri MPS (568 unique measures). As discussed later in section 5.3, the comprehensiveness of a measure list has a direct impact on the technical potential.

***Table 9. MPS Measure Lists Comparison***

| Utility | Residential Measures | Non-Residential Measures | Total Measures |
|---|---|---|---|
| Big Rivers (KY, 2023)[70] | 65 | 115 | 180 |
| CenterPoint (IN, 2022)[71] | 172 | 184 | 356 |
| Duke Energy (IN, 2021)[72]) | 110 | 273 | 383 |

[69] Big Rivers MPS at 2-8.
[70] *Id.* at 2.4.2.
[71] 2022 Demand Side Management Market Potential Study at 10, Table 3-2, included as an attachment to the Centerpoint Energy 2022/2023 Integrated Resource Plan (May 2023), https://midwest.centerpointenergy.com/assets/downloads/planning/irp/2022-2023%20IRP%20-%20Volume%202%20of%202.pdf.
[72] Nexant Inc., *Duke Indiana DSM Market Potential Study* at 31 (Apr. 7, 2021), Attachment B to Reply Comments of Duke Energy Indiana, IURC, https://www.in.gov/iurc/files/Reply-of-Duke-Energy-Indiana-to-2021-IRP-Draft-Directors-Report.pdf (last accessed Mar. 7, 2024).

| | | | |
|---|---|---|---|
| NIPSCO (IN, 2021)[73] | 182 | 272 | 454 |
| Consumers Energy (MI, 2021)[74] | 122 | 349 | 471 |
| Ameren Missouri (MO, 2020)[75] | 201 | 367 | 568 |

[redacted]

***Figure 5. MPS Measure List Comparison***

A few examples of notable omissions from the measure list include:

- Residential: home energy reports, appliances that exceed ENERGY STAR, HVAC equipment that exceeds ENERGY STAR, heat pump dryers
- Non-Residential: networked lighting controls, linear LED lighting[76], compressed air leak repair, retro commissioning, facility energy management systems

[73] NIPSCO, *Demand Side Management Market Potential Study, Volume I Electric Energy Efficiency Potential*, Tables 5-1, 6-1 (2021), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-irp-appendix-b.pdf?sfvrsn=1ae0251_6.

[74] Cadmus, *Electric Energy Waste Reduction Potential Study 2021-2040*, Table 13 (June 10, 2021), https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf ("Consumers MPS").

[75] GDS Associates Inc., Ameren Missouri 2020 DSM Market Potential Study, at 32 (Mar. 2020), https://efis.psc.mo.gov/Document/Display/38894.

[76] The Big Rivers MPS includes a non-residential measure called "LED Bulbs / Fixtures." However, in response to JI Request 2-6, Clearspring indicated that this measure "represents traditional LED screw-in bulbs of different sizes in a commercial setting." Linear lighting is the most common type of lighting used in non-residential buildings, accounting for 83% of interior lighting in commercial spaces according to the DOE. Linear lighting is not subject to the EISA

The Big Rivers MPS also failed to include measures that would be considered emerging technologies. According to ACEEE, "Assumptions about emerging technologies (ETs) can have a noticeable impact on potential results, particularly for those studies that consider long-term savings potential (i.e., ten years out or more)."[77] Each of the studies reviewed for the measure list comparison include multiple emerging technology measures such as smart appliances, advanced controls, variable refrigerant flow heat pumps, and strategic energy management. The Consumers Energy MPS includes 170 unique emerging technology measures, including 112 measures that are expected to be commercially viable prior to 2030.[78]

## 5.2. QUALITATIVE SCREENING

The initial measure list identified by Clearspring included 273 measures, consisting of 86 residential and 187 non-residential measures.[79] 54 of these measures provide gas-only savings, such as high efficiency boilers, and were appropriately removed prior to the study. However, 39 measures were removed subjectively, using a "Qualitative Screening Tool," even though the measures provide savings which are entirely or partially electric.[80]

The qualification screening is a series of questions designed to gauge appropriateness of the measure for inclusion in potential programs. Measures that fail the qualitative screening are removed from the study. The following questions were employed during qualitative screening:[81]

- *Technological maturity*: Is the technology experimental or have its benefits been proven and validated?
- *Market maturity and market transformation*: Is this technology already achieving significant penetration in the market? If so, free riders may be a key concern.
- *Utility match*: Does the proposed measure fit with the characteristics of Big Rivers?
- *Availability of competing measures:* Are there multiple measures that can achieve similar results? Is one measure superior to another?
- *Impact measurement and quantification:* Can the energy and peak demand impacts be quantified, measured, and tracked in a way that confirms a reliable cost-benefit calculation in future assessments?

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lighting standards. Navigant Consulting, *2015 U.S. Lighting Market Characterization*, DOE, at Table (Nov. 2017), https://www.energy.gov/sites/prod/files/2017/12/f46/lmc2015_nov17.pdf; DOE, *Enforcement Policy Discussion for General Service Lamps (GSLs)*, at slide 3, (May 2022), https://www.energy.gov/sites/default/files/2022-05/GSL%20Backstop%20Enforcement%20Webinar%20May%204%202022.pdf.

[77] Cracking the TEAPOT at 15.

[78] Consumers MPS, Appendix C at C-1 to C-2.

[79] Big Rivers MPS at E-2.

[80] *Id.* § 2.4.2; Appendix A–Appliance Standards Change List.

[81] Big Rivers MPS § 2.4.1.

- *Level of member acceptance:* Are members likely to accept the proposed measure, and is it easily integrated into their appliance portfolio?

While it may be reasonable to exclude measures that are not applicable to a utility and its service territory, such as a gas-only measure for an electric-only utility, it is unreasonable to exclude measures from a market potential study based on subjective evaluations of market potential or acceptance. The market potential study itself should be used to address these concerns in the form of economic selection. Adjustment factors such as availability, saturation, and awareness are intended to address these issues within the study. None of the other market potential studies reviewed in section 5.1 employed a qualitative screening process.

In response to Joint Intervenor Request No. 2-3(b), Clearspring provided reasons for measure exclusion during the qualitative screening, beyond fuel type match, which include:

- Low market/savings potential
- Difficult to monitor
- Complicated measure calc[ulation]
- Overly complex / requires detailed downstream work

It is inappropriate to eliminate measures based on subjective estimates of market/savings potential. A MPS analysis includes factors to account for remaining market potential, and measures with lower market potential can still contribute meaningful savings. In the case of the Big Rivers MPS, market potential is addressed by the Availability Factor and Adoption Factor.

It is not the job of an MPS to determine if a measure is difficult to implement or evaluate. These are issues that are addressed during program design. In fact, the Big Rivers MPS is clear to point out that the MPS does not represent a proposed program design.[82] One of the measures eliminated from the study is home energy reports, on the basis that it is difficult to monitor. Residential behavioral programs are commonplace in numerous other jurisdictions, are routinely accounted for in market potential studies, and have a well-established evaluation protocol within the Department of Energy ("DOE") Uniform Methods Project.[83]

A sampling of measures that were inappropriately eliminated due to subjective analysis of market potential or program design considerations include:

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[82] *Id.* § 1.5.4.

[83] James Stewart & Annika Todd, *Chapter 17: Residential Behavior Evaluation Protocol: The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures September 2011 – August 2020*, National Renewable Energy Laboratory ("NREL") (2020), https://www.nrel.gov/docs/fy21osti/77435.pdf.

*Table 10. Subset of measures eliminated during Qualitative Screening*

| Sector | Measure | Reason for Elimination[84] |
|---|---|---|
| Residential | High Efficiency Pool Pumps | Low market potential |
| Residential | Home energy reports | Behavioral / difficult to monitor |
| Residential | Shower Timer | Behavioral / difficult to monitor |
| Non-Residential | High Speed Rollup Doors | Program match/complicated measure calc |
| Non-Residential | Industrial Air Curtain | Program match/complicated measure calc |
| Non-Residential | Economizer Repair and Optimization | Overly complex / requires detailed downstream work |
| Non-Residential | Kitchen Demand Ventilation Controls | Standards/Low market |
| Non-Residential | Notched V Belts for HVAC Systems | Low savings potential |
| Non-Residential | Scroll Refrigeration Compressor | Low market potential |
| Non-Residential | Numerous dairy/agriculture measures | Low market potential |

## 5.3. TECHNICAL POTENTIAL

The definition of technical potential generally does not differ across studies, and technical potential is not affected by inputs such as avoided costs or incentive levels. Therefore, comparing technical potential across jurisdictions is a reasonable way to benchmark studies. Figure 6 shows the technical potential, as a percentage of sales, for Big Rivers and five geographically similar electric-only market potential studies. Big Rivers is the lowest, at 22% of sales.

[84] Big Rivers response to Joint Intervenors data request 2-3.

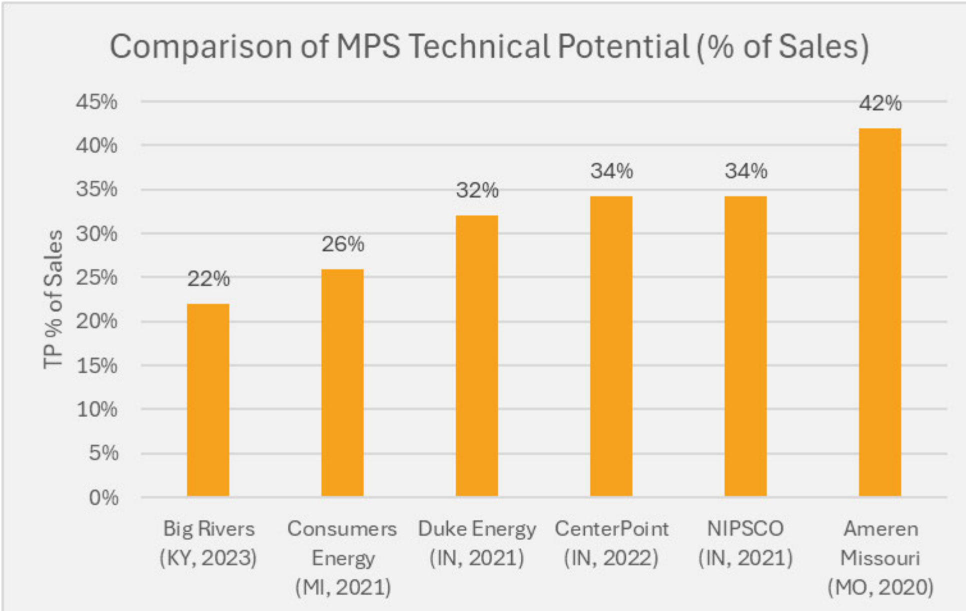


***Figure 6. MPS Technical Potential Comparison***

The comprehensiveness of measures analyzed in an MPS has a direct impact on the overall technical savings potential. According to ACEEE, "Technical potential is limited by the types of commercially available and emerging technologies that the analyst or commissioning entity includes in the analysis."[85] As noted above in Figure 5, the Big Rivers MPS has the least comprehensive measure list, which contributes to the lowest technical potential among geographical similar jurisdictions shown in Figure 6.

Technical potential is also influenced by assumptions regarding measure savings and remaining market adoption. The Big Rivers MPS relies heavily on the Illinois TRM for measure savings assumptions, as do studies performed in Indiana and Missouri. Therefore, the differences in Technical Potential can be primarily attributed to the comprehensiveness of the measure list and assumptions regarding remaining market potential (which Clearspring refers to as "Availability Factor"). Considering this, the findings of technical potential shown in Figure 6 are especially notable since Big Rivers has a very limited history with DSM programs in comparison to the other utilities, and therefore would be expected to have more remaining technical potential. For example, the Consumers Energy MPS identified more remaining technical potential even though they have been implementing programs since 2008, with a statutory minimum of 1% of sales since 2016 and achievements of 2% of sales since 2021.[86] Big Rivers and its members, meanwhile, have implemented a limited set of

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[85] Cracking the TEAPOT at 7.

[86] State and Local Policy Database: Michigan: Utilities, ACEEE (Aug. 2020), https://database.aceee.org/state/michigan.

programs between 2012 and 2019, and only one minor program since then.[87] It stands to reason, therefore, that the Big Rivers service territory would have more technical potential remaining than Consumers Energy, yet as shown in Figure 6 above, the MPS found the opposite.

Finally, a comprehensive list of measures can help identify savings opportunities within all end-use categories including the "Other" end-use. For the Big Rivers MPS, the "Other" end-use represents 11.1%[88] of the residential baseline electricity, but the residential savings within "Other" only represent 2%[89] of the sector total.

## 5.4. ECONOMIC POTENTIAL

Clearspring used the following economic benefit-cost tests to evaluate measures in the MPS:[90]

- Total Resource Cost ("TRC")
- Participant Cost ("PCT")
- Utility Cost ("UCT")
- Rate Impact Measure ("RIM")

Measures in which the net present value of potential benefits are greater than the potential costs have a benefit-cost ratio ("BCR") of greater than one (1.0) and are considered cost-effective. For the Big Rivers MPS, Clearspring eliminated measures that fail the TRC.[91]

**Economic Benefits**

The economic benefits for these tests include avoided costs for capacity, avoided costs for energy, and net reductions in operating, maintenance, or other costs (such as reduced water usage).[92] Importantly, Clearspring did not include the avoided cost of transmission and distribution ("T&D") since "Big Rivers' load is not expected to grow significantly during the study period, putting the value of those benefits (beyond normal system maintenance) in doubt."[93] This statement is inconsistent with the load forecast presented in the Big Rivers IRP, which shows demand growth of 2.19% annually, and energy growth of 3.84% annually, over the next 10 years.[94] While most of this load growth is associated with Direct Serve customers,

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[87] Big Rivers attachment to response to Joint Intervenors data request 2-15(c), at page 102 of 126.
[88] MPS, Figure 2.1.
[89] MPS, Table 3.2.
[90] Big Rivers MPS § 1.4.1.
[91] *Id.* § 1.5.2.
[92] *Id.* § 1.4.1.
[93] *Id.* at 1-6.
[94] Big Rivers 2023 IRP, Tables 2.2.8(a), 2.2.8(b).

the T&D costs necessary to support this growth may be reduced or delayed through energy efficiency within member service territories.

Clearspring also failed to consider the economic benefit of resiliency due to DSM. Resiliency typically refers to the ability to maintain operations through, and recover from, outages and major disruptive events. Resiliency is always an important consideration in utility system planning, so it is prudent to consider the resilience value provided by DSM resources. According to ACEEE, "Many energy-efficient technologies included in utility programs can increase building energy resilience, priming utilities to lead building energy resilience efforts. Envelope measures, building control systems, and connected devices can improve the capacity of a building to retain livable conditions for longer during extreme temperatures, hurricanes, and wildfires."[95] Multiple utilities and states have defined processes to value resiliency quantitatively, including the net present value calculation proposed by Efficiency Vermont, program-level cost-effectiveness evaluations in Minnesota, and estimation of risk in Maryland.[96] The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM for DERs") includes resilience in its framework for benefit-cost analysis.[97]

**Economic Costs**

The economic costs for the benefit-cost analysis tests include the incremental cost of the measure, which is "the difference between the costs of the energy efficient alternative and its less efficient counterpart, plus net installation, site preparation or disposal costs, if any."[98] As discussed later in section 5.7, Clearspring failed to consider funding from the Inflation Reduction Act in the MPS evaluation. As such, the costs used in the TRC, PCT, UCT, and RIM tests are all inflated since the IRA funding source is external to both the utility system and the participant.

The NSPM for DERs notes that federal tax incentive or rebates should be considered as a benefit (or a reduction of cost) for the TRC and PCT tests.[99] While the NSPM for DERs notes that tax incentives should not be included in the UCT test, utility incentives may be reduced due to federal funding and therefore a benefit (or reduced cost) would accrue under the UCT.

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[95] Rohini Srivastava et al., *2024. Valuing Resilience Benefits in Utility Building Retrofit Programs*, ACEEE, at viii (Mar. 5, 2024), https://www.aceee.org/research-report/b2402.

[96] *Id.* at viii, 20.

[97] *National Energy Screening Project (NESP), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, (Aug. 2020), https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf. ("NSPM for DERs"*).

[98] Big Rivers MPS, § 1.4.1.

[99] NSPM for DERs, Table F-5.

**Combined Impact on Economic Potential**

In excluding the benefits of avoided T&D costs and increased resiliency, and failing to consider significant external funding sources, the Big Rivers MPS analysis quantified inappropriately low benefit-cost ratios ("BCRs"). As a result, some measures may have been improperly excluded from the study, and the portfolio of measures in the Achievable and Program Potential scenarios will reflect artificially low cost-effectiveness scores.

When compared against geographically similar electric-only market potential studies, the Big Rivers MPS shows the lowest level of Economic Potential as a percentage of Technical Potential (70%, Figure 7). This finding means that Big Rivers is screening out the largest amount of savings between Technical Potential and Economic Potential. Clearspring's omission of avoided T&D, resiliency, and failure to account for external funding are contributing factors to this outcome.

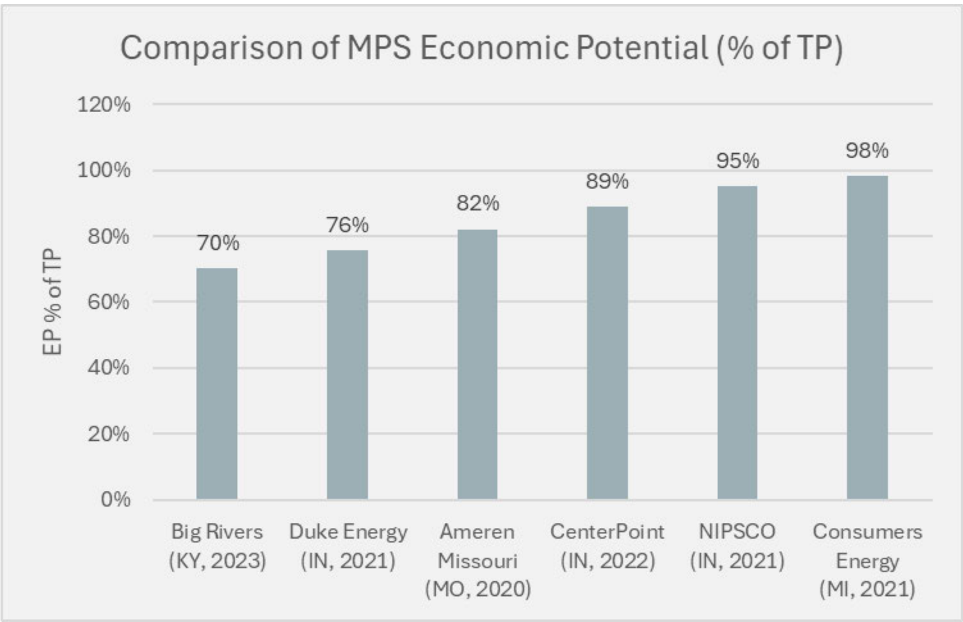


*Figure 7. MPS Economic Potential Comparison*

## 5.5. ACHIEVABLE POTENTIAL

Clearspring used the following formula to calculate achievable potential within the Big Rivers MPS:

*End-Use Economic Potential (MWh) x Program Factor (%) x Adoption Factor (%) x Measure-Life Factor (%) = End-Use Achievable Potential (MWh)*[100]

The Program Factor is an adjustment that Clearspring used to represent “a percentage of measure savings that passes the participant test in the multi-perspective models after an assumption of Big Rivers paying 100 percent of the incremental cost.”[101]

The Participant Cost Test (“PCT”) uses the incremental cost when evaluating the cost-effectiveness of energy efficiency measures. Incremental cost refers to the additional cost incurred by implementing the energy efficiency measure compared to the cost of the baseline or standard practice.

When there is a 100% incentive for energy efficiency measures, it means that the incentive covers the entire incremental cost of implementing the efficiency measure over the baseline measure. In this scenario, the participant's cost would effectively be zero, as they would not have to pay anything out of pocket. Therefore, it is highly unlikely for a measure with a 100% incentive to fail the PCT because the participant's costs are effectively eliminated, making the cost-benefit ratio highly favorable. Therefore, the adjustments made to the non-residential sector in HVAC, refrigeration, and other end-uses, due to a percentage of measures that “failed the participant test at the 100 percent of incremental cost incentive” are inappropriate.

Furthermore, Clearspring noted that HVAC and water heating end-uses were de-rated by the Big Rivers poverty rate of 16%, to represent a market barrier. As with the PCT, this adjustment is illogical in the context of 100% incentives. A customer’s income level should not influence the adoption rate of measures with 100% incentive levels unless the measure is a retrofit, in which case the customer would be making an unplanned investment. If Clearspring’s intent was to account for retrofit measures, the poverty rate adjustment of 16% should be scaled by the weighted portion of retrofit measures within the relevant end-use categories.

## 5.6. PROGRAM POTENTIAL

Program Potential is a further subset of Achievable Potential based on a defined budget amount. According to the MPS, “Program potential differs from achievable potential in that it focuses on the amount of demand-side savings projected based on a specific program budget and includes administrative cost, promotion, and incentive payments. This study estimates program potential based on an annual budget scenario of $1 million in total expenditure.”[102] The $1 million budget identified for the Program Potential scenario

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[100] Big Rivers MPS, § 2.6.3.
[101] *Id.*
[102] *Id.* § 1.5.4.

represents a small fraction of the Achievable Potential, roughly 10% of the average annual spending of $9.6 million.[103] The budget level selected is hypothetical and arbitrary; neither the MPS nor the IRP provide rationale for selection of a $1 million budget. In response to Joint Intervenors data request 1-45(a), Big Rivers justified the $1 million budget stating "it believes that is a reasonable amount, which is also consistent with analyses conducted in prior IRP filings."[104] Yet in past filings, Big Rivers notes that DSM programs were not modeled as a resource in its IRP since the load reductions are small and "would not change the PLEXOS model's overall results."[105] The magnitude of the load reductions are principally a result of the arbitrary selection of a $1 million budget for the Program Potential. The Program Potential budget could have been as much as $9.6 million annually, and the Program Potential savings could have increased by a factor of 2.7.[106]

To develop the Program Potential portfolio, Clearspring first used an age-replacement method to quantify savings based on an end-of-life replacement rate.[107] The portfolio budget was then developed by "multiplying the program MWh by the $/MWh measure cost derived from the multi-perspective evaluation models. An adoption factor based on the percentage of survey respondents who indicated they did not intend to adopt energy efficient measures and a budget factor were then used to scale the total cost up or down to match the program-level budget."[108] This approach does not optimize the Program Potential in the same way that an actual DSM portfolio would be constructed. With a limited budget, a DSM portfolio should be optimized to prioritize savings from the most cost-effective measures, while still ensuring comprehensiveness of measures. Doing so maximizes the savings within the limited resources available to the program. An optimized portfolio would result in increased cost-effectiveness scores, relative to the maximum achievable, but that is not the case for the Big Rivers MPS. The Achievable Potential scenario and the Program Potential scenarios have nearly identical TRC scores, at 3.0[109] and 3.1[110] respectively.

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[103] Achievable Potential has a 10-year spending level of $96 million, or $9.6 million average annual spending, according to Big Rivers response to Joint Intervenors data request 1-30(a).
[104] Big Rivers response to Joint Intervenors data request 1-45(a).
[105] Case No. 2020-00299, *In the Matter of Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation*, Response to Commission Staff's Request 1-28 (Ky. P.S.C. Mar. 19, 2021).
[106] Big Rivers MPS, Table ES-1 at E-3. The Achievable Potential total of Residential and Non-residential is 229,932 MWh, which is 2.7 times the Program Potential total of 84,618 MWh (*see* Big Rivers 2023 IRP, Table 5.2(d).
[107] Big Rivers MPS § 2.6.4.
[108] *Id.*
[109] Big Rivers response to Joint Intervenors data request 1-30(b).
[110] Big Rivers MPS at E-3.

## 5.7. INFLATION REDUCTION ACT

Clearspring considered the impact of several state and federal programs that offer financial incentives.[111] Examples include the Business Energy Investment Tax Credit ("ITC") and Low Income Home Energy Assistance Program ("LIHEAP"). Incentive programs such as these are an important consideration in a market potential study since they can influence the magnitude of savings. Non-utility incentives can increase measure adoption due to reduced customer cost, increased awareness of the measure(s), and supply chain efforts to promote the target measure(s).

The Inflation Reduction Act is a notable omission from the federal programs considered by Clearspring. The IRA provides tax credits and rebates for numerous energy efficiency measures,[112] as shown in Table 11 (for residential measures). The state of Kentucky has received an allocation of $134.2 million for IRA consumer rebates and program administration.[113] This historic infusion of funding will have a profound impact on the adoption of energy efficiency measures within Kentucky and Big Rivers member territories.

***Table 9: IRA Tax Credits and Rebates available for Residential Energy Efficiency Measures***

| Measure Category | | Energy Efficient Home Improvement Credit (25C)[114] | Home Electrification and Appliance Rebates[115] | Home Efficiency Rebates[116] |
|---|---|---|---|---|
| Eligible Measures | Insulation and Air Sealing | 30% of cost | 50-100% of cost up to $1,600 | N/A |
| | Windows | 30% of cost up to $600 total | N/A | N/A |
| | Doors | 30% of cost up to $500 total | N/A | N/A |

[111] Big Rivers MPS § 1.7.
[112] H.R.5376, Inflation Reduction Act of 2022, 117th Cong., §§ 50121, 50122 (2022).
[113] *Home Energy Rebates Map: Kentucky*, Dept. of Energy ("DOE") (last updated Feb. 21, 2024), https://www.energy.gov/save/rebates ("Home Energy Rebates Map: Kentucky").
[114] *Energy Efficient Home Improvement Credit*, IRS (last updated Feb. 1, 2024), https://www.irs.gov/credits-deductions/energy-efficient-home-improvement-credit.
[115] Home Electrification and Appliance Rebate and Home Efficiency Rebate information according to the DOE Home Energy Rebate website, Office of State and Community Energy Programs. *Home Energy Rebates Frequently Asked Questions: Household and Technology Eligibility Questions*, DOE, Response 23, https://www.energy.gov/scep/home-energy-rebates-frequently-asked-questions#household (last visited Feb. 28, 2024) ("Home Energy Rebates FAQs").
[116] *Id.*

| | | | | |
|---|---|---|---|---|
| | Central Air Conditioners | 30% of cost up to $600 per item | N/A | N/A |
| | Heat Pumps | 30% of cost up to $2,000 per year | 50-100% of cost up to $8,000 | N/A |
| | Heat Pump Water Heaters | 30% of cost up to $2,000 per year | 50-100% of cost up to $1,750 | N/A |
| | Whole Home Retrofits | N/A | N/A | 50-80% of cost up to $8,000 |
| Income Restrictions | | None | < 150% AMI | Highest rebate limited to < 80% AMI |
| Availability | | January 1, 2023 | Estimated 2025-26[117] | Estimated 2025-26 |

The tax credits and rebates shown in Table 11 will directly reduce a customer's incremental cost of implementing energy efficiency. Failing to consider the effect of these IRA financial benefits within the Big Rivers MPS means:

- Some measures that failed the Economic Potential screening may have otherwise passed if the IRA funding were considered.
- The cost for Achievable Potential, which assumes 100% program-funding incentives, was too high since it failed to reflect funding that will be provided by the IRA.
- The cost for the Program Potential was too high and the adoption rate was lower than it should have been since the IRA funding was not accounted for. The Program Potential scenario assumes incentives at 35% of incremental cost, which would have been less with IRA funding. Furthermore, the adoption rate would have been higher for IRA-relevant measures given improved customer economics and awareness.

In response to a request for an explanation why the IRA was not considered, Clearspring witness Joshua Hoyt provided the following rationale:

> *Please refer to Appendix B, Big Rivers 2023 IRP, Demand-Side Management Potential Study, section 2.6.4, page 2-12. This study is a Potential study and not a Design study. The purpose is to estimate how much energy and demand savings are available in the market. No specific programs were created as a result of this focus. In addition, the timing of the availability of the incentives in*

117 Kentucky received early administrative funding and is preparing to submit a full funding application. Home Energy Rebates Map: Kentucky. Full applications are due January 31, 2025. Home Energy Rebates FAQs, Response 58 (as of July 27, 2023).

*the Act and the window of time for the annual Program Potential do not align, making the Act's incentives difficult to incorporate even if specific programs were created for this study.*[118]

This response is puzzling for several reasons. Mr. Hoyt implies that Big Rivers would need to create programs to realize the benefits of IRA. This is not true. The Energy Efficient Home Improvement Credits are claimed when a homeowner files their taxes. The Kentucky Office of Energy Policy has the responsibility of applying for and determining the methods of distribution of Home Electrification and Appliance Rebates and Home Efficiency Rebates. The Office of Energy Policy plans to submit an application for these programs[119] prior to the January 31, 2025 deadline.

Additionally, Mr. Hoyt contends that the availability of IRA funding does not overlap with the window of time for the Program Potential analysis, which spans 2024-2033. As shown in Table 11, the Energy Efficient Home Improvement Credits are already available now, while Home Electrification and Appliance Rebates and Home Efficiency Rebates are expected to become available in 2025 or 2026. Clearly, there is significant overlap with the timing of the Program Potential scenario.

## 5.8. MPS REFERENCE SOURCES

One of the stated objectives of the Big Rivers MPS was to "[d]evelop databases of energy efficiency and demand response measures in the residential and non–residential sectors to reflect current industry knowledge of energy efficiency and demand response."[120] Like many market potential studies, the Big Rivers MPS relied on DSM Technical Reference Manuals ("TRMs") as a crucial source of knowledge regarding measure lists and the associated measure savings, cost, and life.

Unfortunately, despite the objective to use the most current industry knowledge, Clearspring relied on sources which were multiple years old. All of these sources had more current versions readily and publicly available, as shown below in Table 12.

*Table 102: Reference Documents Used in Big Rivers MPS*[121]

| Reference Document | Version Used in MPS | Newer Version Available at Time of Study |
|---|---|---|

[118] Big Rivers response to Joint Intervenors data request 2-9(b).
[119] *Inflation Reduction Act (IRA) Projects*, Kentucky Energy and Environment Cabinet, https://eec.ky.gov/En Big Rivers response to ergy/Programs/Pages/program-projects.aspx, (last visited Feb. 28, 2024).
[120] Big Rivers 2023 IRP, § 5.2 at 77.
[121] Sources listed in Big Rivers MPS § 1-8.

| | | |
|---|---|---|
| Illinois Technical Resource Manual[122] | v9 (2021) | v11 (2023), published 9/22/22[123] |
| Pennsylvania Technical Resource Manual | 2021 | N/A |
| Iowa Technical Resource Manual[124] | v4 (2020) | v7 (2023), published 9/15/22[125] |
| Michigan Technical Resource Manual | 2017 | 2023, published 11/21/22[126] |
| A National Review of the Cost of Energy Saved Through Utility Sector Energy Efficiency Programs, ACEEE | 2009 | 2014[127] and 2021[128] |

As a result, the Big Rivers MPS relied on outdated and incomplete information in the development of energy savings potential. For example, the Illinois TRM added 41 new measures across v10 and v11,[129] and revised dozens of existing measures. None of these measure additions or revisions were accounted for in the Big Rivers study since Clearspring relied on the obsolete Illinois v9 from two years prior. In addition to Illinois, Clearspring relied on an Iowa TRM that was three years old, and the Michigan TRM, known as the Michigan Energy Measures Database, that was six years old.

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[122] The Illinois Commerce Commission provides versions of the Technical Resource Manuals on its website, available at https://www.icc.illinois.gov/programs/illinois-statewide-technical-reference-manual-for-energy-efficiency.

[123] *2023 Illinois Statewide Technical Reference Manual for Energy Efficiency Version 11.0*, Illinois Energy Efficiency Stakeholder Advisory Group (SAG) (Sept. 22, 2022), https://www.ilsag.info/wp-content/uploads/IL-TRM-Version-11.0-Volumes-1-4-Compiled-Final.pdf.

[124] The Iowa Utilities Board provides versions of the Technical Resource Manuals on its website, available at https://iub.iowa.gov/regulated-industries/energy-efficiency-programs.

[125] *Iowa Energy Efficiency Statewide Technical Reference Manual Version 7.0*, Iowa Utilities Board (filed Sept. 22, 2022), https://iub.iowa.gov/regulated-industries/energy-efficiency-programs.

[126] Michigan Energy Measures Database, Mich. Pub. Serv. Comm'n, https://www.michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database (last visited Mar. 7, 2024).

[127] Maggie Molina, *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs*, ACEEE (Mar. 2014), https://www.aceee.org/research-report/u1402.

[128] Charlotte Cohn, *The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-Funded Efficiency Programs in 2018*, ACEEE, (June 2021), https://www.aceee.org/topic-brief/2021/06/cost-saving-electricity-largest-us-utilities-ratepayer-funded-efficiency.

[129] Illinois TRM v10 includes 19 new measures as compared to v9, summarized here https://www.ilsag.info/wp-content/uploads/IL-TAC_Final-Deliverable-Memo-_09242021.pdf. V11 includes an additional 22 new measures as compared to v10, summarized here https://www.ilsag.info/wp-content/uploads/IL-TAC_Final-Deliverable-Memo_09232022.pdf

# 6. SUMMARY OF RECOMMENDATIONS

Based on our review of the Companies' IRP and its responses to our discovery, we offer the following recommendations to Commission Staff and Big Rivers:

**Stakeholder Process**

- Facilitate IRP stakeholder meetings and provide stakeholders with a schedule of when modeling and supporting data will be shared.
- Build time into the schedule to allow stakeholders to submit feedback on information shared.
- Schedule follow up meetings as necessary to discuss feedback that results in points of disagreement.
- Assist stakeholders with obtaining an EnCompass project-based license, or providing stakeholders with a project based license, to allow interested intervenors the ability to perform their own modeling runs in the same software package(s).

**IRP Inputs and Modeling**

- Relax supply side resource constraints to allow the model to have the option to select a portfolio of renewable, battery storage, and/or capacity purchases to replace the Green units in 2029.
- Allow battery storage resources to be selected within the model starting in 2027.
- Model battery storage resources at longer durations than four-hours.
- Evaluate a higher capacity factor for new solar resources.
- Provide supporting information for the development of the BREC CC costs.
- Model higher capital costs for the BREC CC.
- Expand the evaluation of unit retirements to include several dates for the Green units and Wilson.
- Develop a distributed generation forecast with growth rates in line with historical averages.
- Energy efficiency resources should be evaluated as forced in resources to test the impact on expansion and dispatch results if the resource is not selected in the capacity expansion step.
- Evaluate the impact that off-system sales revenue has on the selection of the BREC CC through the application of market sales limits.

**MPS Development**

- The MPS should include a comprehensive list of measures, including emerging technologies. Qualitative screening should only occur based on fuel type match.

- Technical potential should be based on a comprehensive list of measures, and the availability factor should be based on current, comprehensive, and geographically relevant research.
- Economic screening should consider a wider range of benefits, including avoided T&D, resiliency, and funding available through federal programs such as the Inflation Reduction Act.
- Program factor and financial barrier adjustments in Achievable Potential should not apply when incentives are modeled at 100%.
- Program Potential should be established using reasonable incentive levels with a savings-optimized portfolio of measures, without an arbitrary budget cap.
- Funding available through the Inflation Reduction Act should be included in the calculations of cost-effectiveness and adoption rate for relevant measures.
- Measure assumptions should be based on the most current available technical reference manual or other reference sources from geographically similar jurisdictions.

# Exhibit A

# Chelsea Hotaling
# Consultant

## Professional Summary

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such as IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

## Education

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

## Experience

2021-present: Consultant, Energy Futures Group, Hinesburg, VT

2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT

2019-2020: Analyst, Energy Futures Group, Hinesburg, VT

2018-2019: Intern, Sommer Energy, Canton, NY

2016-2019: Research Assistant, Clarkson University, Potsdam, NY

## Selected Projects

- The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP (2023). Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio as an alternative to the preferred plan presented in Santee Cooper's 2023 IRP (2023).

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- The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)
- GridLab. Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)
- Sierra Club. Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Appalachian Citizens' Law Center, and Mountain Association. Reviewed and provided comments on Kentucky Power's 2023 Integrated Resource Plan. (2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice. Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Reviewed and provided comments on Evergy's 2023 IRP Annual Update. (2023) Reviewed and provided comments on Evergy's 2022 IRP Annual Update. (2022) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy. Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs. (December 2019)
- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

## Publications

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

## Expert Testimony

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC,* on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. *In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC,* on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. *Application for a Determination of Ratemaking Principle*, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

# Chelsea Hotaling
# Consultant

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.

# Dan Mellinger, PE
# Principal

ENERGY FUTURES GROUP

## Professional Summary

Dan specializes in the design, planning and administration of energy efficiency programs, with an emphasis on commercial and industrial sectors. He provides technical consultative services on efficient technology capabilities, market analysis, technology adoption, energy savings potential, industry standards, training, and financing. He is experienced in the policy and regulation of demand-side management goal setting, budgets, annual reporting, and performance incentives. Dan has consulted on hundreds of commercial efficiency projects across many jurisdictions nationwide and has designed and administered industry-leading commercial lighting programs. He received his degree in Electrical Engineering from Michigan State University, is a licensed Professional Engineer, is a Certified Energy Manager, and is Lighting Certified.

## Experience

2020-present: Principal, Energy Futures Group, Hinesburg, VT

2017-2019: Senior Consultant, Energy Futures Group, Hinesburg, VT

2016-2017: Senior Strategic Planner, VEIC, Burlington, VT

2009-2016: Efficiency Vermont Commercial Lighting Lead, VEIC, Burlington, VT

2005-2009: Efficiency Vermont Business Energy Consultant, VEIC, Burlington, VT

1999-2005: Semiconductor Manufacturing Engineer, IBM, Essex Junction, VT

## Education

B.S., Electrical Engineering, Michigan State University, 1999

## Certifications

Professional Engineer (PE) – State of Vermont

Lighting Certified (LC) – National Council on Qualifications for the Lighting Professions

Certified Energy Manager (CEM) – Association of Energy Engineers

Leadership and Management Professional Certificate – University of Vermont

## Select Projects

- Citizens Action Coalition (Indiana). Critically review and deliver testimony on market potential study findings, action plans, and multi-year DSM plans for each of the Indiana investor-owned utilities. Delivered and defended testimony quantifying the potential for higher levels of energy efficiency as an alternative resource to a proposed 850 MW natural gas plant. (2018-present)

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- Natural Resources Defense Council (Michigan, Illinois, Colorado). Provide technical consultative insights on commercial and industrial energy-saving programs and measures. Critically review multi-year demand side management (DSM) plans filed by Michigan and Colorado utilities. Deliver and defend regulatory testimony on energy waste reduction (EWR) plans for Consumers Energy and DTE in Michigan. (2017-present)
- General Services Administration (GSA). Provide technical support and assistance, as a subcontractor to Cadmus Group, in developing strategies to achieve 100% carbon free electricity for all federal government agencies by 2030. Develop a forecast model using agency consumption data mapped against multiple scenarios of NREL's Cambium 2022 data model by state and balancing authority. (2023-present.)
- DesignLights Consortium (DLC). Conduct research for and provide technical assistance on the evolution of the technical requirements for the *Solid-State Lighting (SSL)* and *Networked Lighting Control (NLC)* programs. Incorporate LED product requirements that support the integration of networked lighting controls. (2018 to present)
- California Alternative Energy and Advanced Transportation Financing Authority. Provide technical assistance on the design and implementation of commercial and residential energy efficiency financing programs. Calculate and report program energy savings estimates to the program administrators and regulators. (2017 to present)
- Rhode Island Energy Efficiency & Resource Management Council. Provide technical consultative insights on commercial and industrial energy-saving measures. Advise on new technologies, programs, and models for accelerating innovation in achieving aggressive energy savings. (2018 to present)
- Connecticut Energy Efficiency Board. Provide technical consultative insights on commercial and industrial energy-saving programs and measures. Lead technical consultant to the Research, Development and Demonstration (RD&D) team. (2018 to present)
- Vermont Agency of Natural Resources. Developed a data tracking framework and recommendations, in partnership with Cadmus Group, as technical consultants to the Vermont Climate Council. (2021-2022)
- Massachusetts Energy Efficiency Advisory Council. Provide technical consultative insights on commercial and industrial energy-saving programs and measures. (2018 to 2022)
- Independent Electricity System Operator (IESO) Ontario. Perform a jurisdictional scan of commercial lighting programs across the U.S. and Canada. Develop program design recommendations for networked lighting controls and lighting design. (2022)
- EfficiencyOne (Nova Scotia). Provide program design consultation and recommendations for the Business, Non-Profit, and Institutional (BNI) market within the 2023-2023 DSM Plan (2021).
- Iowa Environmental Council. Provide program design recommendations and best practices as part of a collaborative effort to launch a midstream pilot with MidAmerican Energy. (2020-2021)
- Northwest Energy Efficiency Alliance (NEEA). Senior advisor on the market assessment of Luminaire Level Lighting Controls. Perform secondary data analysis, energy code review, and in-depth interviews of relevant market actors. (2019-2020)

- Alliance to Save Energy. Conducted research and published a report on lifetime savings potential, peak demand savings potential, and cost effectiveness of commercial LED and networked lighting controls. (2019)
- DLC. Developed an analysis and published product adoption and energy savings forecasts for commercial and industrial LED lighting and networked lighting controls. (2018)
- Minnesota Center for Environmental Advocacy. Delivered and defended testimony quantifying the potential for higher levels of energy efficiency as an alternative resource to a proposed 525 MW natural gas plant. (2018)
- Technical Reference Manual Development (Vermont, Ohio, Illinois, Iowa, DC). Developed commercial lighting TRM characterizations for Efficiency Vermont prescriptive and midstream programs. Technologies addressed: LED lamps and fixtures, fluorescent lamps and fixtures, and lighting controls. Contributed to TRM lighting measure characterizations in Ohio, Illinois, Iowa, and Washington, DC. (2011-2017)
- Efficiency Vermont Technology Roadmap. Created a 3-year, comprehensive emerging-technology planning roadmap for Efficiency Vermont. Roadmap addressed technologies and residential, commercial, and industrial customer classes. Designed an interactive and dynamic Excel roadmap platform. (2017)
- Vermont Demand Resources Plan. Developed a 20-year forecast of efficiency potential from commercial and residential lighting for the Vermont Demand Resources Plan (DRP). Forecast metrics: adoption, energy and demand savings, and incentive spending. The Vermont Public Utility Commission uses the DRP to set Efficiency Vermont's 3-year budgets and goals. (2016-2017)
- DLC LED Qualification Program. Contributed toward the concept, launch, and growth of the DLC LED qualification program, in collaboration with Northeast Energy Efficiency Partnerships (NEEP) and regional utilities. Lead technical advisor on specification development. (2010-2016)
- Vermont Efficiency Excellence Network. Supported the design and launch of the Efficiency Excellence Network for Efficiency Vermont trade allies. Helped establish trade group participation criteria, assisted in trade ally recruiting, and delivered program and technical training. (2013-2016)
- Efficiency Vermont Midstream Lighting Program. Contributed to the design of, and eventually administered, the nation's first commercial lighting midstream program. Continuously expanded and evolved the program to keep pace with emerging technology and market changes. Managed distributor relationships and increased participation to 100% of electrical distributors. (2009-2016)
- Lighting Design Program. Created a program that pairs Vermont commercial customers with professional lighting designers on retrofit projects to improve comprehensiveness. The resulting energy savings per project increased 50% compared to typical lighting retrofits. (2010-2016)
- Statewide Municipal Street Lighting Program. Assisted in the design and launch of a partnership between Vermont municipalities and utilities for upgrading street lighting to LED. Used financial strategies to address the non-depreciated asset costs while minimizing the municipality investment cost. Provided technical support to the program administrator and municipalities. (2010-2014)
- Vermont Commercial Lighting Market Analysis. Used data analytics to evaluate and forecast product adoption and energy savings potential in the Vermont commercial lighting market. Developed new program strategies based on the data insights. (2013-2016)

## Select Publications


- Mellinger, Dan, Julian Ricardo, Lisa Wilson-Wright, and Matt Woundy. 2020. *2019-2020 Luminaire Level Lighting Controls Market Assessment.* Northwest Energy Efficiency Alliance. https://neea.org/img/documents/2019-2020-Luminaire-Level-Lighting-Controls-Market-Assessment.pdf.
- Mellinger, Dan, and Liesel Whitney-Schulte. 2020. *A New Sales Pitch*. LD+A, November. https://www.ies.org/lda/a-new-sales-pitch/.
- Mellinger, Dan. 2019. *Commercial & Industrial Lighting Lifetime and Peak Demand Savings Analysis.* Alliance to Save Energy. https://www.ase.org/lighting-savings-report.
- Mellinger, Dan. 2018. *Energy Savings Potential of DLC Commercial Lighting and Networked Lighting Controls.* DesignLights Consortium. https://www.designlights.org/resources/energy-savings-potential-of-dlc-commercial-lighting-and-networked-lighting-controls/.
- Mellinger, Dan, and Lauren Morlino. 2018. *Getting to 50: How Vermont Plans to Reach 50% Market Adoption of Linear LED by 2025*. ACEEE Summer Study. http://www.aceee.org/files/proceedings/2018/#/paper/event-data/p120.
- Goetzler, Bill, George Lawrence, Dan Mellinger, and Mary Yamada. 2018. *Lighting Isn't Finished: Pivoting beyond the LED Bulb*. ACEEE Summer Study. http://www.aceee.org/files/proceedings/2018/#/paper/event-data/p134.
- Mellinger, Dan. 2014. *Lighting Efficiency Programs: Second Half Strategies.* LD+A, October.
- Mellinger, Dan, and Connie Samla. 2013. *Maximizing ROI Through Good Design.* LD+A, April.
- Arnold, Gabe, Mike Burke, Dave Lahar, Dan Mellinger, and Paul Markowitz. 2012. *A Win-Win-Win for Municipal Street Lighting: Converting Two-Thirds of Vermont's Street Lights to LED*. ACEEE Summer Study. https://aceee.org/files/proceedings/2012/start.htm.
- Baldacci, Kate, Eileen Eaton, Rebecca Foster, Dan Mellinger, Margaret Song, and Liesel Whitney-Schulte. 2010. *Defining a Framework for Comprehensive Commercial and Residential Lighting Programs*. ACEEE Summer Study. https://aceee.org/files/proceedings/2010/start.htm.


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