COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 2021-00393**

SUPPLEMENTAL POST-HEARING COMMENTS OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Filed: August 22, 2022

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I. INTRODUCTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") respectfully submit these Supplemental Post-Hearing Comments regarding the Companies' 2021 Joint Integrated Resource Plan ("2021 IRP") and the hearing held in this proceeding on July 12 and 13, 2022.

II. THE COMPANIES' TRANSFORMATIVE IRP APPROPRIATELY BALANCES THE TRANSITION TO RENEWABLE RESOURCES WITH THE NEED TO PROVIDE SAFE AND RELIABLE SERVICE AT THE LOWEST REASONABLE COST.

After all that was said and done in the two-day hearing, it remains true that the Companies' current IRP is entirely transformative. Coupling a reasonable future CO_2 regulatory path (assuming that new natural gas combined cycle ("NGCC") units would require carbon capture and sequestration systems ("CCS")) with favorable assumptions about battery storage and solar resource pricing, the Companies' IRP retires almost 2,000 MW of coal-fired generation and adds 2,100 MW of solar generation.[1] Beginning in 2034, the IRP's generation portfolio would serve customers' energy requirements with 18% utility-scale solar energy—more than six times the percentage of solar energy serving America today—and would reduce the Companies' CO_2 emissions 26% from 2021 levels.[2] Notably, not having a CCS requirement actually results in even lower CO_2 emissions and lower revenue requirements.[3] Moreover, the Companies' approach to modeling possible future carbon regulations in this IRP resulted in a base-load, base-fuel generation portfolio that is *dramatically* higher in renewable energy resources than the Companies' 2018 IRP, which modeled carbon pricing and resulted in a base-load, base-fuel portfolio that added

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[1] IRP Vol. I at 8-28. Note that the 2,100 MW of new solar capacity does not include the Companies' existing 10 MW Brown Solar Facility, the Companies' Solar Share Facility, the Rhudes Creek solar PPA, or the Ragland solar PPA.
[2] IRP Vol. I at 8-30.
[3] *See* Companies' Response to KIUC PHDR 1.

just 400 MW of solar by 2033 using carbon prices that rose to $26 per short ton by 2033.[4] Thus, the Companies' IRP is both transformative relative to the Companies' and America's current generation portfolios—and relative to the Companies' most recent IRP that modeled carbon pricing—and is consistent with the IRP regulation's directive to pursue "an adequate and reliable supply of electricity at the lowest possible cost for all customers" based on reasonable assumptions about the future.[5]

III. THE COMPANIES REASONABLY AND CONSISTENTLY ACCOUNTED FOR POSSIBLE REGULATION OF CARBON EMISSIONS IN THEIR 2021 IRP.

Several lines of questioning at the hearing in this proceeding addressed the appropriateness and completeness of the Companies' accounting for possible carbon emissions regulations by assuming that CCS technology would be required for new NGCC units by the end of the IRP period. In particular, two lines of questioning deserve comment: (1) why the Companies did not also assume that simple-cycle combustion turbines ("SCCTs") would also require CCS, and (2) how and whether the Companies' assumptions were consistent with PPL Corporation's subsequent statements concerning future carbon emissions.[6] In addition to addressing these two lines of questioning, the Companies' comments below also address a related issue, namely the reasonableness (or lack thereof) of using carbon pricing as a proxy for future carbon emission regulations.

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[4] *See* Case No. 2018-00348, IRP Vol. I at 5-39, Table 5-15 (Oct. 19, 2018), available at https://psc.ky.gov/pscecf/2018-00348/rick.lovekamp%40lge-ku.com/10192018102925/3-LGE_KU_2018_IRP-Volume_I.pdf.
[5] 807 KAR 5:058 Necessity, Function, and Conformity.
[6] *See, e.g.*, Hearing Video Day 1 at 15:43:12-15:44:15 and 15:49:49-15:50:04.

A. The Companies Reasonably Assumed NGCC Would Require CCS but SCCT Would Not Because a CCS Requirement Would Render SCCT Uneconomical in All Plausible Future Scenarios.

Contrary to the implications (or outright assertions) of certain lines of questioning at the hearing that it was somehow inconsistent for the Companies' 2021 IRP to assume a CCS requirement for NGCC but not for SCCT,[7] there is nothing inconsistent at all about the approach the Companies took. As the Companies' witnesses noted, it would be prohibitively uneconomical to require CCS technology for a SCCT unit, at least based on the National Renewable Energy Laboratory ("NREL") 2021 Annual Technology Baseline ("ATB") assumptions about the cost of such technology in 2036 for NGCC units.[8] The reason it would be prohibitively uneconomical is because of the nature of SCCTs as peaking units; because they are not intended to run for extended periods, adding hundreds of millions of dollars of cost for CCS would render an SCCT uneconomical in all plausible future scenarios. In short, such a requirement would be tantamount to prohibiting the construction of any new SCCT units, which in turn would either significantly imperil reliable service or dramatically increase the cost of a future that depends in large part on intermittent renewable generation. For that very reason, it seems unlikely that such a requirement would eventuate.

Moreover, it would appear the Companies are not alone in their assessment of the unlikelihood of a CCS requirement for SCCTs. Notably, the NREL 2021 ATB, which provides cost projections for dozens of permutations of generating technology, including NGCC with or without CCS, does not include *any* cost projections for SCCT with CCS, but rather only for SCCT without CCS.[9] Therefore, at least as of the time of publishing their 2021 ATB, no less an authority

[7] *See, e.g., id.*
[8] *See id.*; Hearing Video Day 1 at 15:50:08-15:51:35.
[9] *See* Companies' Response to PSC 2-2(b).

than NREL, which is a laboratory of the U.S. Department of Energy, did not appear to believe SCCT with CCS was a plausible technology for which to estimate costs.

Relatedly, there was some discussion at hearing about why the Companies did not address carbon regulations with regard to their existing coal fleet.[10] As the Companies noted in their previously filed Responsive Comments and as Mr. Sinclair addressed at hearing,[11] it is doubtful that new coal units will be built in the United States given current New Source Performance Standards for such units. For that reason, the regulatory focus (at least at the federal level) has shifted to regulating gas units' carbon emissions, not coal units' carbon emissions, precisely because existing coal units are expected to retire as their current expected lives end.

To be clear, the Companies are not asserting and have not asserted that the only possible or plausible means of regulating carbon emissions is requiring CCS for NGCC, though it is noteworthy that the recent federal Inflation Reduction Act includes increased incentives for CCS by up to 70%,[12] and it would increase CCS deployment 13-fold by 2030 according to the Princeton University Zero Lab.[13] Certainly if the Commission Staff's Report directs the Companies to model multiple kinds of possible future carbon regulation, as the Commission Staff recently directed Duke Energy Kentucky to do in future IRPs, the Companies will perform such modeling in their future IRPs. But the Companies continue to believe the approach they took in the 2021 IRP was

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[10] *See, e.g.*, Hearing Video Day 1 at 13:03:10-13:05:48.
[11] *See* Companies Responsive Comments at 29-30 (May 20, 2022); Hearing Video Day 1 at 15:53:28-15:54:30.
[12] *See, e.g.*, S&P Capital IQ Market Intelligence, "US climate deal heralded by carbon capture fans as steroid shot to industry," available at https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=71433160 ("Carbon capture groups cheered the budget reconciliation deal announced July 27 by U.S. Senate Majority Leader Chuck Schumer, D-N.Y., and Sen. Joe Manchin, D-W.V. The agreement would increase subsidies by up to 70% for facilities that capture their emissions.").
[13] *See* slide 13 of the August 4, 2022 Zero Lab presentation available at https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-04.pdf ("The Inflation Reduction Act would increase the use of carbon capture 13-fold by 2030 relative to current policy (including demonstration projects spurred by the Bipartisan Infrastructure Law)."). *See also id.* at slides 11 and 18.

reasonable based on the information available at the time about a plausible course for carbon regulation over the 2021-2036 time period.

B. The Companies' Modeling Shows that Carbon Pricing Is Not a Reliable Proxy for All Forms of Possible Future Carbon Regulation and that Carbon Pricing between $15 and $25 per Short Ton Strongly Favors NGCC When CCS Is Not Required.

At least one line of questioning at hearing highlighted the differences in results when assuming a carbon pricing regime and a CCS requirement for new NGCC units.[14] This exchange is notable because it, as well as the Companies' data supplied in response to PSC 2-1, demonstrates that carbon pricing is not a reliable proxy for other forms of carbon regulation. The table below, taken from the Companies' response to PSC 2-1(b), shows a stark contrast between modeling (i) a requirement for NGCC with CCS and no carbon pricing and (ii) either a $15 or $25 per ton carbon price with no CCS requirement:

Optimal Portfolios by Carbon Price (Base Load, Base Fuel Prices)

	NGCC Requires CCS			NGCC Does Not Require CCS		
CO_2 Price ($/short ton)	**$0**	**$15**	**$25**	**$0**	**$15**	**$25**
Additional Coal Retirements	None	MC3	MC3; GH3-4	None	MC3-4; GH3-4	MC3-4; GH3-4
NGCC w/o CCS MW	N/A	N/A	N/A	1,539	3,078	3,078
NGCC w/ CCS MW	0	0	513	0	0	0
SCCT MW	1,320	0	440	0	0	0
Solar MW	2,100	4,100	3,900	0	2,900	3,600
Wind MW	0	1,200	1,900	0	0	0
Battery Storage MW	200	1,700	1,400	100	300	300

Moreover, the Companies' response to the Commission Staff's Post-Hearing DR No. 1 confirms that there is no carbon price between $15 and $150 per ton for which the resulting optimal portfolio is consistent with the portfolio resulting from a CCS requirement for NGCC. This is important to note for future IRP and CPCN proceedings; it simply is not the case that modeling carbon pricing

[14] *See, e.g.*, Hearing Video Day 2 at 08:21:19-08:23:23.

is a reliable proxy for a variety of different kinds of possible future carbon regulation. Therefore, modeling more than one potentially likely carbon regulation approach is advisable, at least when actual capital commitments are at issue.

Also and equally notable is that when there is no CCS requirement for NGCC, NGCC is a large part of an optimal generation portfolio at every carbon price level the Companies modeled from $0 to $150 per ton,[15] and some amount of new NGCC without CCS is part of an optimal portfolio with carbon pricing up to and including $120 per ton.[16] Indeed, 2,565 MW of new NGCC capacity without CCS is part of an optimal portfolio even assuming a $55 per ton carbon price, as Duke Energy Kentucky did in its most recent IRP.[17] It is also noteworthy that NGCC with CCS is part of the optimal portfolio when there is a CCS requirement for such units with a carbon price as low as $25 per ton.[18] In short, it is reasonable to expect that NGCC technology may be an integral part of the Companies' economical generating fleet for the foreseeable future, particularly in the absence of a CCS requirement for new NGCC units.

C. Recent Regulatory Developments, Not a Desire to Slow Net Metering or Other Renewable Energy Deployments, Drove the Companies' Decision to Model NGCC with CCS rather than Carbon Pricing in their 2021 IRP.

Contrary to certain questioning at hearing, the Companies did not choose to model a CCS requirement for NGCC rather than carbon pricing in their 2021 IRP to somehow mitigate the Commission's inclusion of an avoided carbon cost component of the Companies' net metering rates or in any way to slow the deployment of renewable energy resources in the Companies' service territories.[19] Rather, the Companies chose to model carbon constraints in the form of a

[15] *See* Companies' Response to PSC 2-1(b); Companies' Response to PSC PHDR 1.
[16] *See* Companies' Response to PSC PHDR 1.
[17] *See Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Case No. 2021-00245, Duke IRP at 30 (June 21, 2021).
[18] *See* Companies' Response to PSC 2-1(b).
[19] *See, e.g.,* Hearing Video Day 2 at 17:01:33-17:03:00.

CCS requirement rather than a carbon price because there was no indication that a carbon price was likely at the state or federal level at the time the Companies were drafting their IRP, but there were indications that carbon emission constraints for gas-fired generation could be under consideration.[20] As the Companies noted in their responsive comments filed in this proceeding and as the Companies' witnesses testified at hearing, subsequent events have supported this view, including remarks by the White House's national climate advisor, Gina McCarthy,[21] the U.S. Environmental Protection Agency's ("EPA") April 2022 draft technology white paper that lays the procedural foundation for establishing a new source performance standard—not a carbon price—for new gas-fired units,[22] the recent Supreme Court opinion in *West Virginia v. EPA*,[23] and the recent federal Inflation Reduction Act's enhanced carbon capture incentives, as discussed above. Therefore, it was reasonable at the time the Companies drafted their IRP to model a CCS requirement for NGCC in lieu of a carbon price to account for plausible future carbon regulations, and there have been no environmental regulatory events since to suggest that the Companies' approach was unreasonable.

In addition, any suggestion that the Companies are slow-walking the deployment of renewable energy resources lacks historical support or support in this record. The Companies built the first utility-scale solar facility in Kentucky at the E.W. Brown Generating Station, have a Solar Share program and facility, and have entered into PPAs for hundreds of megawatts of solar for large customers (including 25 MW of solar for all customers), all in addition to the Companies'

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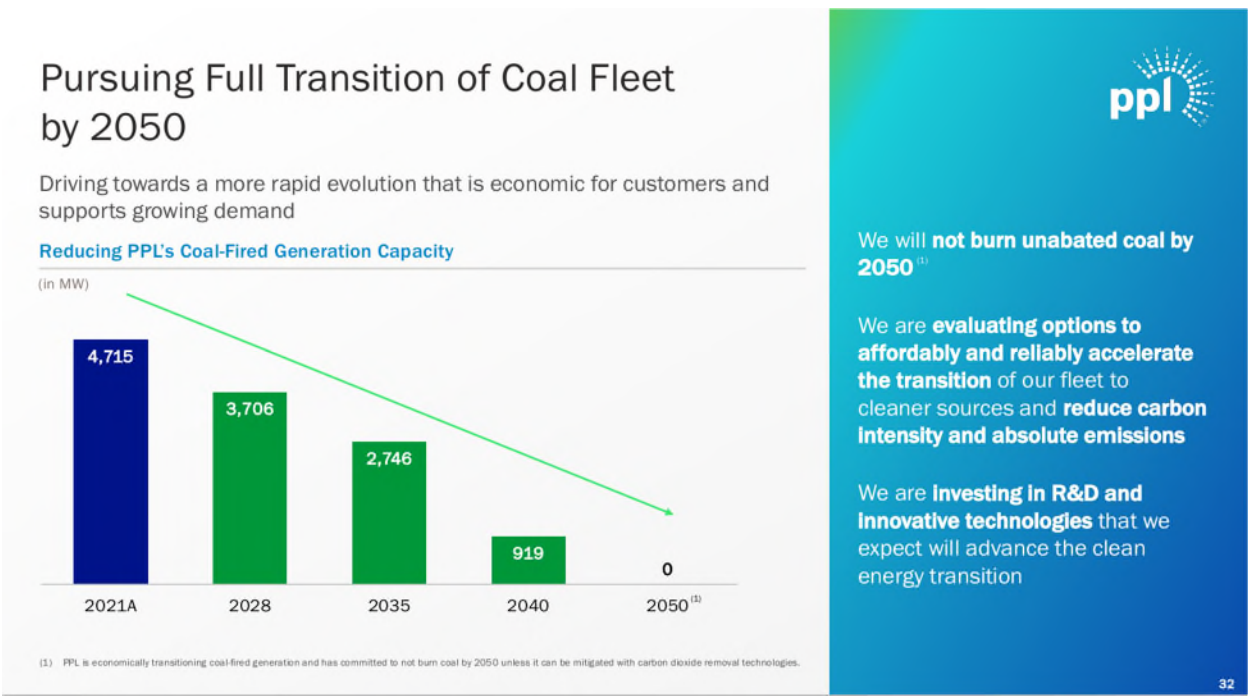
[20] *See, e.g.*, IRP Vol. I at pgs. 5-20 and 6-11; Companies' Response to PSC 1-9; Companies' Response to JI 1-10.
[21] Wall Street Journal, "Biden's Great Energy and Climate Contradiction" (Mar. 25, 2022), available at: https://www.wsj.com/articles/joe-bidens-energy-contradiction-lng-europe-gas-companies-russia-ukraine-ginamccarthy-11648244471.
[22] 7 EPA, Office of Air and Radiation, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units" (April 21, 2022), available at: https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april2022.pdf.
[23] Available at https://www.supremecourt.gov/opinions/21pdf/20-1530_n758.pdf.

historic hydro resources. Also, the base-load, base-fuel scenario of the Companies' 2021 IRP includes over 2,100 MW of solar while retiring about 2,000 MW of coal-fired generation. Thus, any assertion that the Companies have sought or are seeking to act in a deliberately slow manner to deploy renewable energy in Kentucky is in spite of, not supported by, the Companies' actions. Any such assertion would also be contrary to PPL's Carbon Emission Plan, as discussed below.

D. The Companies' 2021 IRP Is Consistent with PPL's Carbon Emission Reduction Plan.

As the Companies' witnesses testified at hearing, the Companies' 2021 IRP is consistent with PPL's publicly stated carbon emission plan, including the June 9, 2022 PPL Corporation Investor Day presentation.[24] Much discussed at hearing was the following slide from the Investor Day presentation:



[24] Available at https://pplweb.investorroom.com/PPL-Corporation-2022-Investor-Day.

As Mr. Bellar explained at hearing, the 2021 IRP is entirely consistent with this slide.[25] The first two green bars, which show the Companies' projected coal-fired generating capacity in the years 2028 and 2035, reflect the same coal-unit retirements reflected in the 2021 IRP.[26] The subsequent projections (2040 and 2050) are beyond the scope of the 2021 IRP and this proceeding; they are therefore irrelevant per se. Indeed, under the current IRP regulation, the Companies' 2050 coal-fired capacity will not become relevant until the Companies file their 2036 IRP.

That notwithstanding, PPL's commitment not to burn unabated coal by 2050—almost fifteen years after the end of the 2021 IRP's planning period—is fully consistent with the 2021 IRP. As Mr. Bellar testified at hearing, there is no particular statute, regulation, or market circumstance that would *require* all coal generation either to retire or operate only with carbon dioxide removal technology by 2050, which is what PPL has committed to do.[27] Therefore, because there is no economic expectation or anticipated regulatory requirement that would mandate what PPL has committed to do by 2050, there was nothing related to that commitment to reflect in the 2021 IRP. Rather, the retirements anticipated in the 2021 IRP, as well as the Companies' expected coal-unit retirements by 2040, show a retirement trajectory that is consistent with—but is not driven by—PPL's 2050 commitment.

IV. THE COMPANIES HAVE FULLY COMPLIED WITH THE COMMISSION'S MODELING TRANSPARENCY REQUIREMENTS.

Contrary to the insinuations of one line of questioning at hearing,[28] the Companies have fully complied with the modeling transparency requirements articulated in the Commission's

[25] Hearing Video Day 2 at 16:52:00-16:53:09.
[26] *See* IRP Vol. I at 5-18, Table 5-4.
[27] *See, e.g.*, Hearing Video at 16:54:50-16:59:58.
[28] Hearing Video Day 1 at 17:51:24-17:56:54.

September 24, 2021 Order in the Companies' 2020 rate cases.[29] The relevant text from that Order states:

> For this reason, the Commission finds that, in future cases, including those updating LG&E/KU's IRP and QF rates, LG&E/KU should improve the transparency of their avoided energy and any other costs that are calculated using proprietary software by increasing access to the software, inputs, and assumptions relied upon. *While the Commission will not at this time prescribe a method for doing so, LG&E/KU should submit, within 90 days of the entry of this Order, a filing that details how LG&E/KU will increase the transparency of their modeling to the Commission.* At a minimum, LG&E/KU's plan should allow for one model re-run per intervening party and the Commission per proceeding, upon a party's request, and for the provision of inputs and assumptions to the models in native formats within the initial filing.[30]

As the emphasized Order text above shows, *there was no modeling transparency requirement in effect* when the Companies filed their 2021 IRP on October 19, 2021; rather, there was a requirement for the Companies to file a modeling transparency plan by 90 days from September 24, 2021, which the Companies timely did on December 22, 2021.[31] Therefore, the Companies did not disregard or violate any applicable modeling transparency requirement when they filed their 2021 IRP on October 19, 2021, because no such requirement existed at the time.

Furthermore, neither the Commission's September 24 Order nor the Companies' modeling transparency plan includes a requirement for the Companies to *solicit* requests for additional modeling runs from any party; rather, the Commission's Order states that the Companies' modeling transparency plan "should allow for one model re-run per intervening party and the Commission per proceeding, *upon a party's request*."[32] The Companies' modeling transparency plan does just that:

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[29] *See* Case Nos. 2020-00349 and 2020-00350, Order at 29-30 (Ky. PSC Sept. 24, 2021).
[30] *Id.* (emphasis added).
[31] *Id.*
[32] *Id.* (emphasis added).

> **In future proceedings, the Companies propose to allow for one model re-run per intervening party and the Commission per proceeding, upon a party's request.**
>
> To accommodate this request, the Companies propose that a party submit an updated Attachment B highlighting their desired input changes as an attachment to their data request. The Companies will complete the model run and provide the associated model outputs at the end of the ten business-day period allotted for responding to data requests.[33]

In accordance with that plan, which was and is consistent with the Commission's Order, the Companies conducted additional modeling runs for the only party that requested them, namely Commission Staff in PSC 2-1 and PSC 2-3.

Indeed, far from failing to be transparent about their modeling, the Companies provided unprecedented levels of modeling and other data into the record of this proceeding (over 30 gigabytes of data). At the request of certain parties' counsel, the Companies' personnel also directly consulted with parties' outside experts to help them understand the data provided. And upon request by the Commission Staff, the Companies reran their models to include certain carbon pricing levels and allow the production model to choose additional economic unit retirements. Thus, the Companies have in no way violated modeling transparency requirements; rather, they have provided greater modeling transparency than in any of their previous IRP proceedings.

V. THE COMPANIES ADEQUATELY ADDRESSED DEMAND-SIDE MANAGEMENT, ENERGY EFFICIENCY, AND DISTRIBUTED GENERATION IN THE 2021 IRP.

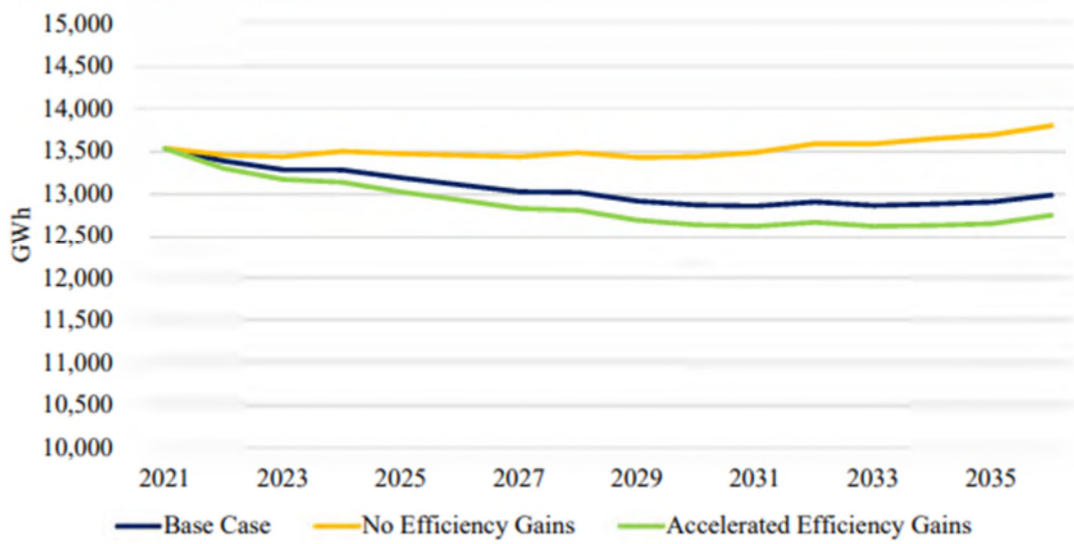
Contrary to certain questioning at hearing,[34] the Companies fully complied with the Commission's IRP regulation regarding DSM-EE modeling and discussion in the 2021 IRP. Nowhere does the IRP regulation require utilities to develop or even consider specific new DSM-

[33] Case Nos. 2020-00349 and 2020-00350, Companies' 2020 Rate Case Response to September 24, 2021 Ordering Paragraphs 9 & 10 at 4 (Dec. 22, 2021) (bolded text in original).
[34] *See, e.g.*, Hearing Video Day 2 at 17:36:35-17:38:12.

EE programs as part of the IRP process; rather, the regulation requires utilities to describe and report on DSM-EE efforts that might be planned or underway and are included in utilities' IRPs.[35] The Companies' 2021 IRP fully accounts for existing DSM-EE programs and projections for the currently approved 2018-2025 DSM-EE Program Plan, and it includes an assumed continuation of DSM-EE programs that would achieve the same levels of demand and energy savings as those projected to be achieved by 2025 for the remainder of the IRP planning period.[36]

In addition, the 2021 IRP assumed in its base load scenario that customers would achieve energy efficiency sufficient to reduce annual energy requirements by 6% through a combination of the Companies' DSM-EE efforts and customers' own efficiency improvements.[37] The Companies assumed even greater energy savings in their low-load scenario:[38]

Figure 5-12: Impact of Energy Efficiency Improvements on Residential and Small Commercial Sales Forecast[31]

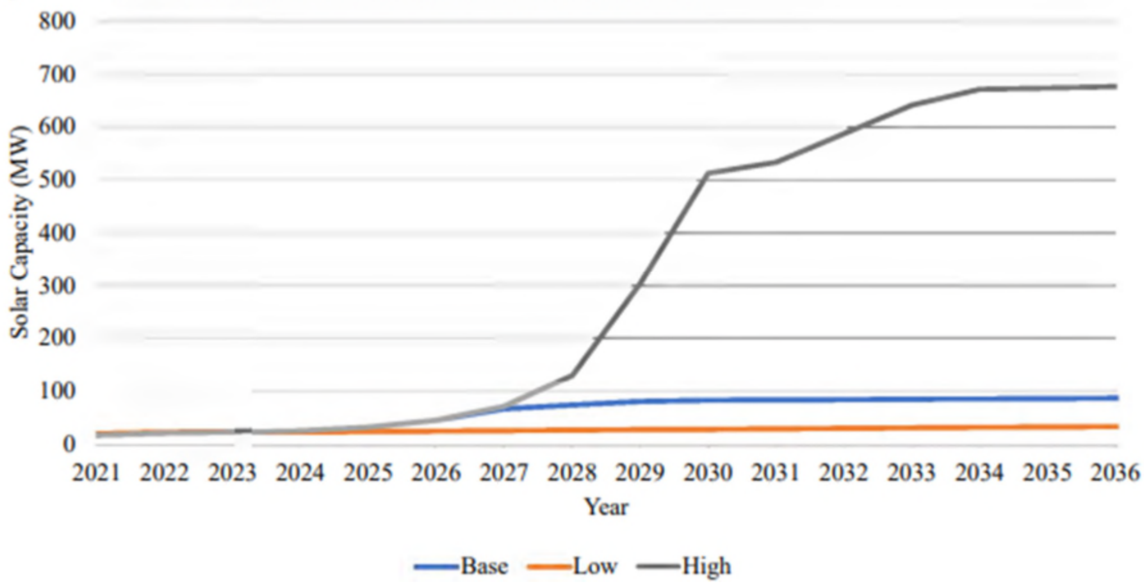


[35] *See* 807 KAR 5:058 Secs. 5(4), 7(2)(g), 7(4)(d), 7(7)(e)(4), 7(7)(g), 8(2)(b), 8(3)(e), 8(4)(a), 8(4)(b), 8(5)(c).
[36] *See* IRP Vol. I at 8-24 and 8-25, Table 8-13.
[37] *See* IRP Vol. I at 5-26.
[38] *See* IRP Vol. I at 5-26 and 5-27, Figure 5-12.

Therefore, although the Companies did not attempt to formulate and model specific new DSM-EE programs in the 2021 IRP, the Companies did assume continuing and growing energy savings resulting from DSM-EE programs and customers' own efforts.

Added to the Companies' DSM-EE and other energy efficiency assumptions were assumptions that customers would add significant amounts of distributed generation, particularly in the high-distributed generation forecast, in which there is no state cap on net metering:[39]

Figure 5-13: Distributed Generation Forecast Scenarios



Taken together, the Companies' DSM-EE, customer energy efficiency, and distributed generation ("DG") assumptions had significant impacts on their load forecasts, most notably the low-load forecast, as shown in the green (DSM-EE) and orange (DG) bars in the energy requirements table below:[40]

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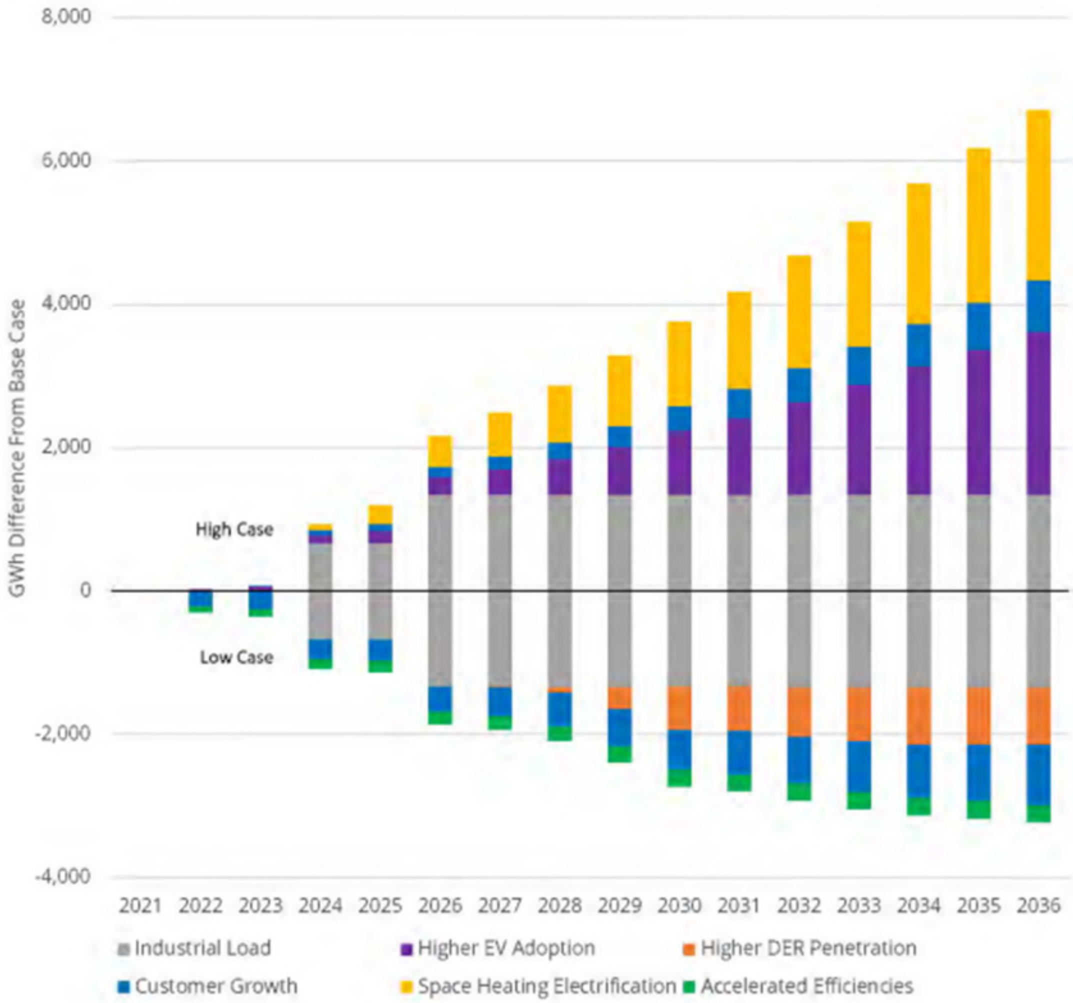
[39] *See* IRP Vol. I at 5-27 – 5-30 and Figure 5-13.
[40] *See* IRP Vol. I at 5-36, Figure 5-20.

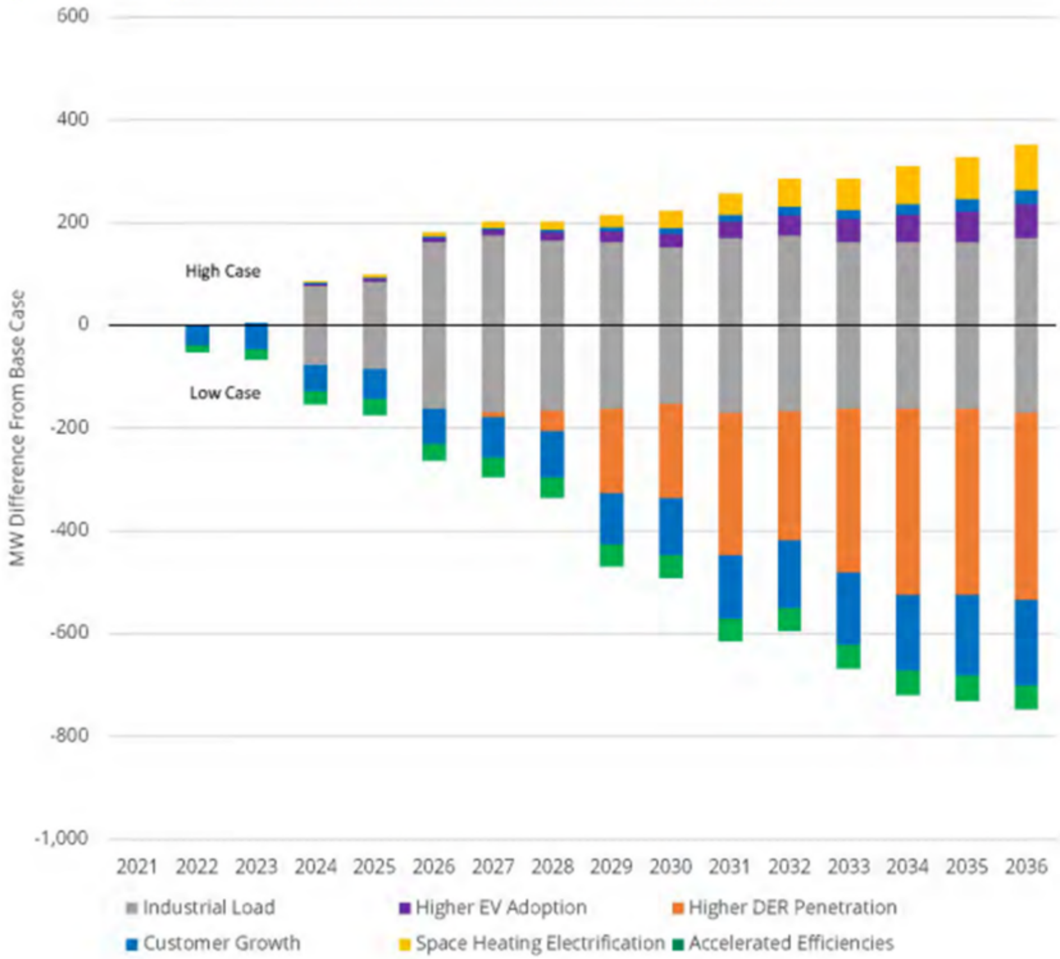
Figure 5-20: High and Low Case Energy Requirements Differences (GWh)



These effects are even more pronounced when considering the load impacts of these items on summer peak demand, again shown in green (DSM-EE) and orange (DG) bars:[41]

[41] *See* IRP Vol. I at 5-38, Figure 5-21.

Figure 5-21: High and Low Case Summer Peak Differences (MW)



Therefore, not only did the Companies comply with the Commission's IRP regulation regarding DSM-EE in the 2021 IRP, they modeled significant levels of customer-side demand and energy reductions, as well as distributed generation, in their base and low-load scenarios.

VI. THE COMPANIES HAVE BEEN REASONABLE AND DILIGENT IN THEIR REVIEW AND DEVELOPMENT OF A NEW DSM-EE PROGRAM PLAN.

At hearing, the Chairman inquired about the diligence of the Companies' development of a new DSM-EE Program Plan since their determination in late 2020 that they would likely have a capacity need in 2028. Indeed, the Companies have been diligent concerning their DSM-EE program portfolio both before and after that determination.[42] First, the Companies have a team of dedicated individuals that not only manage current DSM-EE programs but also research other opportunities on an ongoing basis, not just when preparing to make a DSM-EE, IRP, or other relevant filing. Second, the Companies regularly meet with their DSM-EE Advisory Group to seek input and review program performance; for example, the Companies have met at least annually with the group since the current program portfolio took effect in 2019.[43] Third, the Companies recently sought and obtained Commission approval to increase the budget for the exceedingly well performing Nonresidential Rebates Program.[44] In short, the Companies do not obtain approval for a DSM-EE Program Plan and simply put program research and development on the back burner until the end of the plan's term; rather, they consistently review current programs, research new programs, meet with their DSM-EE Advisory Group, and seek mid-plan program adjustments as needed.

In addition to all the measures noted above and in addition to complying with the Commission's IRP regulations regarding modeling and discussing DSM-EE programs, the Companies have also accelerated their DSM-EE program plan development since their determination that they would likely have a capacity need in 2028. The Companies' DSM-EE consultant, Cadmus, performed a demand response potential study in the first quarter of 2021, and the Companies further retained Cadmus in July 2021 to conduct additional program reviews precisely because the Companies anticipated an upcoming capacity need and desired to deploy cost-effective DSM-EE programming in a new Program Plan to help address that need.[45] Also,

[42] *See* Hearing Video Day 2 at 17:08:39-17:15:15.
[43] *See* https://lge-ku.com/dsm for meeting minutes and presentations.
[44] *See* Case No. 2022-00123, Order (Ky. PSC May 20, 2022).
[45] *See* Meeting Minutes and Presentation from the September 17, 2021 Meeting of the DSM-EE Advisory Group, available at https://lge-ku.com/dsm.

the Companies conducted a survey of their DSM-EE Advisory Group in 2021 to solicit input for developing new and updated DSM-EE programs,[46] and the Companies met twice with their DSM-EE Advisory Group in 2021 as they began the DSM-EE program review and development process.[47] As Mr. Bellar noted during his testimony at hearing, the Companies intend to account fully for cost-effective DSM-EE programs in any upcoming CPCN filing, and they anticipate filing for a new DSM-EE Program Plan close in time to, or simultaneously with, any such CPCN application.[48] Therefore, far from being dilatory in pursuing a new DSM-EE Program Plan, the Companies began actively pursuing such a plan shortly after they determined there likely was an upcoming capacity need in 2028.

It is also important to note that, as Mr. Bellar also explained at hearing, deploying new or expanded DSM-EE programs based on avoided capacity costs is most advantageous to all customers if the Companies deploy the programs as close in time as reasonably possible to the anticipated capacity need.[49] This results from, and is consistent with, the discounting concept the Chairman raised at hearing:[50] the value of avoiding a capacity cost in 2028 *increases* as 2028 approaches. That is why formulating and deploying DSM-EE programs as close in time as reasonably possible to the anticipated capacity need increases the value of such programs—and potentially expands the universe of programs that could be cost-effective. This again shows that the Companies have been reasonable in the timing of their review and development of a new DSM-EE Program Plan.

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[46] *See id*.
[47] *See* https://lge-ku.com/dsm.
[48] Hearing Video Day 2 at 17:08:39-17:15:15.
[49] Hearing Video Day 2 at 17:08:39-17:15:15.
[50] *See id.*

VII. THE COMPANIES HAVE ACTED PRUDENTLY REGARDING OVEC AND WILL CONTINUE TO ACT IN CUSTOMERS' BEST INTEREST.

As Mr. Bellar testified at hearing and as the Companies demonstrated in response to Sierra Club's post-hearing data requests, the Companies continue to dispatch OVEC energy in ways that benefit customers, and OVEC is actually more economical on a per MWh basis than when the Commission approved extending the OVEC ICPA in Case Nos. 2011-00099 and 2011-00100.[51] First, the Companies typically economically dispatch OVEC after their own coal units and Cane Run 7 but before Brown Unit 3 and the Companies' simple-cycle combustion turbines, making OVEC an economical resource to serve customers on an energy basis.[52] Second, as the Companies demonstrated in their response to SC PHDR 1(a), OVEC's average cost per MWh (i.e., OVEC's total cost divided by a given number of MWh) is considerably *lower* today than the average costs upon which the Commission approved extending the OVEC ICPA through 2040 in Case Nos. 2011-0099 and 2011-00100. Therefore, contrary to the misleading implications of Sierra Club's cross-examination, it is not true that OVEC power has become uneconomical on an energy basis or relative to the projected costs of OVEC upon which the Commission approved the ICPA extension.[53]

In addition, it is precisely the Commission's review and approval of the 2011 ICPA extension that makes Sierra Club's repeated references to a Michigan Public Service Commission order regarding Indiana Michigan Power Company's ICPA participation entirely inapt.[54] Unlike the Companies, *Indiana Michigan Power never sought or received the Michigan PSC's approval for the ICPA's extension*: "I&M did not seek approval from the Commission for the decision to

[51] *See, e.g.,* Hearing Video Day 2 at 14:46:35-14:47:00; Companies' Response to SC PHDR 1(a).
[52] *See* Companies' Response to SC PHDR 1(a).
[53] *See id.*
[54] *See* Hearing Video Day 2 at 15:18:13-15:22:36; Sierra Club Comments at 11 and Exh. A (Apr. 22, 2022).

extend the contract in 2004 or 2010."[55] (Notably, the Companies sought and received this Commission's approval for both extensions.)[56] For that very reason, the Michigan PSC quite reasonably reviews Indiana Michigan Power's *total* OVEC ICPA costs annually; unlike this Commission, it did not review or approve projected non-fuel ICPA costs. Therefore, unlike Indiana Michigan Power, it is inapt at best to compare the ICPA's *total* costs to other power supply or demand-side alternatives; rather, the appropriate comparison is to the avoidable ICPA costs, i.e., only those costs under the ICPA that the Companies would not incur if they did not schedule OVEC energy (other than minimum purchase obligations). When making that comparison—the only appropriate comparison—it is clear that the Companies have acted prudently and in customers' interests by scheduling OVEC energy when it is for customers' benefit.[57]

VIII. CONCLUSION

The Companies respectfully submit that their IRP fully satisfies the letter and objective of the Commission's IRP regulation, as well as the recommendations of past Commission Staff reports on the Companies' previous IRPs. The Companies reasonably and adequately accounted for possible carbon emission regulations and DSM-EE, and they complied with all applicable modeling transparency requirements. They have further demonstrated reasonable and prudent conduct concerning OVEC that is in their customers' interests. In short, the Companies' 2021 IRP and their testimony at hearing demonstrate the Companies' ongoing commitment to plan for and provide safe and reliable service at the lowest reasonable cost, both now and for decades to come. To that end, the Companies are well on track to transition their coal-fired generation fleet through lowest reasonable cost options that provide reliable power.

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[55] *See* Sierra Club Comments Exh. A at 13 (Apr. 22, 2022) (emphasis added).
[56] *See* Case Nos. 2011-0099 and 2011-00100, Order (Ky. PSC Aug. 11, 2011); Case Nos. 2004-00395 and 2004-00396, Order (Ky. PSC Dec. 30, 2004).
[57] *See, e.g.,* Companies' Response to SC PHDR 1(a).

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Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

In accordance with the Commission's Order of July 22, 2021 in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), this is to certify that the electronic filing has been transmitted to the Commission on August 22, 2022; and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

Counsel for Kentucky Utilities Company and Louisville Gas and Electric Company