COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

JOINT INTERVENORS' INITIAL COMMENTS ON LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY'S JOINT 2021 INTEGRATED RESOURCE PLAN

Tom FitzGerald
Ashley Wilmes
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602
(502) 551-3675
FitzKRC@aol.com
Ashley@kyrc.org

Counsel for Joint Intervenors
Metropolitan Housing Coalition,
Kentuckians for the Commonwealth,
Kentucky Solar Energy Society and
Mountain Association

Dated: April 22, 2022

Table of Contents

JOINT INTERVENORS' INITIAL COMMENTS ON LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY'S JOINT 2021 INTEGRATED RESOURCE PLAN

Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, "Joint Intervenors") appreciate the opportunity to offer these comments and accompanying expert reports in response to the 2021 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU" or "the Companies").

INTRODUCTION

Integrated Resource Planning is a serious enterprise, and unfortunately the Companies have not done it justice. The inadequacy of the Companies' IRP is reflected in: (1) the choice of process, methodologies, and modeling tools; (2) the failure to consider impacts on and needs of all customers, including low- and fixed-income customers; (3) the neglect of demand-side resources and potentially cost-effective demand-side potential; and (4) the failure to reasonably evaluate risks posed by different resource choices and portfolios.

Unfortunately, these flaws undermine the usefulness and validity of the integrated resource planning exercise. As a result, Joint Intervenors submit that the Companies' 2021 Joint IRP would provide insufficient evidentiary support for selection of new resources and insufficient evidentiary support for the assumed retirement dates of existing generation units.

Joint Intervenors recommend a suite of improvements necessary to make both this and the Companies' next IRP a more meaningful exploration of the lowest-cost and lowest-risk portfolio of resources available to meet customer needs at in a fair, just, and reasonable manner, with affordable rates, and optimizing customer value.

Joint Intervenors' comments are informed in substantial part by the work of experts Anna Sommer and Chelsea Hotaling of Energy Futures Group, and James Owen of Renew Missouri. The experts' reports are provided as Attachments and adopted in full as part of this comment. Joint Intervenors' silence on any issue, analysis, or conclusion advanced in the Companies' IRP should not be taken as support. Joint Intervenors appreciate the Companies having made their modelers available for clarifications needed by the Energy Futures Group.

FACTUAL CONTEXT

Collectively, Kentucky Utilities Company ("KU") and LG&E serve nearly one million electric customers in over ninety Kentucky counties. In the words of Paul Thompson, the Companies' recently retired President, Chairman, and CEO, their "business remains one of the most capital-intensive industries in the world."[1] The capital-intensive nature of utility service is reflected in the Companies' revenue requirements, collectively compelling payments from Kentucky customers in excess of $2.5 billion every year.[2]

Much of that cost is driven by capital investments in developing and maintaining the resources relied on to meet customers' energy needs. Ideally, these capital investments are first studied as part of long-range IRP processes and invariably end up in rate base. In 2018, KU's reported rate base was $3.6 billion, and forecasted to surpass $4.3 billion by 2021.[3] LG&E's

---

[1] Direct Testimony of Paul W. Thompson, at 6, *In the Matter of Elec. Application of Ky. Util. Co. for an Adjustment of its Elec. Rates*, Case No. 2018-00294 (Sept. 28, 2018) ("Thompson Direct").

[2] Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(h)(4), Case No. 2018-00294 (reflecting Kentucky Utilities' annual revenue requirement in excess of $1.5 billion); Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(h)(4), Case No. 2018-00295 (reflecting Louisville Gas & Electric Company electric annual revenue requirement in excess of one billion).

[3] Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(h)(12), Case No. 2018-00294.

reported rate base, provided in their most-recent rate case, was approximately $2.5 billion and rising.[4] On a combined basis, the Companies' rate base reflects over $6 billion of public investment.

These public investments, while strikingly large, do not exaggerate the importance of the essential service being provided. The Companies' customers include households, businesses, and industry; libraries, schools, and hospitals; pharmacies, churches, and museums. All customers depend on the Companies for energy services, and pay rates that are supposed to be fair, just, and reasonable in return.

Integrated Resource Planning is at the core of that compact. Utility resource decisions are a direct and substantial driver of the services available, and the costs paid. In order to ensure good decision-making, it is essential to have quality forecasts of customer needs and robust analysis of all potentially cost-effective options.

Furthermore, fundamentally linked to the utilities' business model, there is now an overarching societal need to rapidly transition our economy to net-zero carbon emissions. The global energy transition is undeniably underway, and its urgency has grown with each passing year. As LG&E and KU presently source 97% of their energy from fossil fuels, the energy transition poses a tremendous but necessary challenge, with risks and opportunities for their customers. The United Nations Intergovernmental Panel on Climate Change warns that we must reduce global carbon emissions by 45% from 2010 levels by 2030 and to net zero by 2050, if we are to have any chance of limiting global warming to 1.5 degrees C.[5] The International Energy

---

[4] Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(h)(12), Case No. 2018-00295.

[5] Intergovernmental Panel on Climate Change, Global Warming of 1.5º C, Ch. 2 at 116 (2018), https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_Chapter2_Low_Res.pdf.

Agency in 2021 published a *Roadmap for the Global Energy Sector* to achieve net zero by 2050, and stated, "The energy sector is the source of around three-quarters of greenhouse gas emissions today and holds the key to averting the worst effects of climate change, perhaps the greatest challenge humankind has faced."[6] In response to this great challenge, PPL (the parent company of LG&E and KU) has joined hundreds of other corporations in making a net-zero carbon commitment.[7] In light of all this, climate change must be considered as a core concern in the Integrated Resource Planning for all electric utilities, an essential factor in the context in which the utilities operate.

DISCUSSION

I. The Companies' process, methodologies, simplifying assumptions, and documentation resulted in an inadequate Integrated Resource Plan.

The Companies' approach to their triennial Integrated Resource Planning exercise leaves much to be desired. In the attached expert report, Anna Sommer and Chelsea Hotaling of Energy Futures Group ("EFG") detail a number of the ways in which the Companies fell short, and make recommendations on how the Companies' process, methodology, resource assumptions, and documentation can be materially improved in the next IRP. (Exhibit 1). The EFG Report is adopted and incorporated in these Comments in its entirety. Key observations from the EFG Report include the following:

1. The Companies' IRP does not identify a least-cost plan or a preferred resource plan. Ex. 1, EFG Report, Section 1.

---

[6] International Energy Agency, Net Zero by 2050: A Roadmap for the Global Energy Sector at 2, Summary for Policymakers, https://iea.blob.core.windows.net/assets/7ebafc81-74ed-412b-9c60-5cc32c8396e4/NetZeroby2050-ARoadmapfortheGlobalEnergySector-SummaryforPolicyMakers_CORR.pdf.

[7] PPL Corp., Sustainability, https://www.pplweb.com/sustainability/climate-action/ (last accessed Apr. 21, 2022).

2. The Companies used different models for capacity expansion and production cost modeling, increasing the possibility of inconsistent assumptions and constraints, increasing opportunities for errors, and reducing transparency. Ex. 1, EFG Report, Sections 2 and 3.4.

3. The Companies used capacity expansion modeling to optimize portfolios in only the final year of the planning period, rather than using the model to optimize decisions about when within the planning period resources should be added or retired. Ex. 1, EFG Report, Section 3.2.

4. The Companies developed individual expansion portfolios for each of nine different scenarios, but never tested how any among those portfolios might perform under a variety of future conditions or scenarios. Ex. 1, EFG Report, Section 3.2.

5. The Companies have not evaluated potentially economically-optimal unit retirements. Ex. 1, EFG Report, Section 3.2.3.

6. The Companies have not evaluated the cost-effectiveness of additional energy efficiency and demand response investments, instead exclusively focusing on supply-side resources. Ex. 1, EFG Report, Section 3.2.2.

7. The Companies have not provided adequate documentation to confirm all the constraints and assumptions used in the modeling. Ex. 1, EFG Report, Section 3.2.4.

8. The Companies performed a single production cost modeling run of a single portfolio (Base Load and Base Fuel scenario portfolio). As a result, the Companies can provide the present value of revenue requirements for only that single portfolio, and no comparison to other portfolios is possible. Ex. 1, EFG Report, Section 3.3.

9. The Companies' IRP does nothing to consider the risks associated with carbon pricing, carbon regulation, or carbon reduction goals. Ex. 1, EFG Report, Section 3.5

10. The Companies are using an outdated approach to reserve margin analysis, using load duration curves incapable of accurately capturing the reliability impacts of variable or time-dependent resources. Ex. 1, EFG Report, Section 4.1

11. The Companies analysis evaluating a range of scenarios for achieving aggressive emission reduction goals is methodologically dubious and appears to misrepresent costs, resource options, resource performance, and efficiency savings. Ex. 1, EFG Report, Section 5.1.

12. The Companies' Solar Intermittency Study is out of sync with applicable balancing standards, current operating conditions, and the capabilities of modern renewable and storage systems. Ex. 1, EFG Report, Section 5.2.

Combined, these flaws mean that the 2021 IRP does not examine all the potentially cost-effective resource options available to the utility; does not provide sufficient information to determine whether the Companies' acquisition plan is lowest cost; does not test the robustness of any portfolio under a variety of future scenarios; and does not consider whether existing units may be economically retired. This is especially concerning in light of the substantial costs and risks posed by the Companies' existing generation portfolio, and the prospect of needing to replace substantial amounts of generating capacity over the next fifteen years, potentially at great cost to customers.

That said, there is considerable potential to improve the Companies' next IRP process, using tools and data already at hand. The EFG Report provides specific recommendations along those lines, including the following:

1. Encourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs, and assumptions including, but not limited to:
   a. The Companies' reserve margin study;
   b. The development and modeling of the portfolios considered in the IRP;
   c. The manner in which unit retirement is evaluated;
   d. The RTO membership analysis;
   e. The source of and manner in which new resource costs and supply are developed, e.g., demand-side management ("DSM") and other distributed energy resources (DERs); and
   f. The modeling tools used in the development of the IRP.

2. Encourage the Companies to negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own

modeling runs in the same software package(s), and encourage the Companies to absorb the cost of these licensing fees.

3. Clarify that upon filing of an IRP, LG&E/KU should make available, on request and ideally simultaneously with filing of the IRP, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual(s).

4. Recommend that the Companies adopt the typical practice of using a single model for capacity expansion and production cost modeling.

5. Direct the Companies to model a full planning period and not just a single year.

6. Recommend that the Companies document their analytical work so that it clearly conveys the steps taken and information relied upon.

7. Encourage the Companies to limit out-of-model adjustment and include as many system costs in the model as is feasible.

8. Direct the Companies to economically evaluate all potentially cost-effective resource options available to it, specifically including a wide range of levels of new and expanded DSM and other DERs such as distributed solar and storage. The DSM levels should be developed through the meaningful and participatory collaboration of the DSM Advisory Group as previously recommended by Staff.

9. Direct the Companies to consider key issues or uncertainties potentially impacting their resource plan, particularly including analysis of the impacts of a carbon price and meeting a significant emission reduction goal, such as PPL’s corporate goal, on the Companies’ resource plans.

10. Encourage the Companies to cease use of the Equivalent Load Duration Curve Model (“ELDCM”) for reliability modeling.

By adopting these recommendations, the Companies can significantly improve their resource planning exercise, better ensuring that future resource decisions will be low cost and low risk customer investments.

II. Integrated Resource Planning should be grounded in an understanding of customer needs and potential impacts on customers.

Joint Intervenors recognize that Integrated Resource Planning is concerned with answering the question of what combination of demand- and supply-side resources, over time, are likely to meet customer needs at the lowest cost with the least risk exposure.[8] Unlike the Companies, however, Joint Intervenors submit that answering that question necessarily requires an examination of customers' needs over the planning period and evaluation of how customers will be impacted by different resource choices. LG&E/KU's 2021 IRP falls short in this regard.

As set out below, the Companies' view that customer needs and customer impacts are irrelevant to resource planning is misplaced. The Companies' demand- and supply-side resources are paid for by their customers and intended to serve customer needs, making it essential to begin an analysis of future resource options by considering customer needs and impacts. With this foundation, integrated resource planning stands the best chance of optimizing customer value from demand- and supply-side investments.

A. The unique needs of low- and fixed-income customers should be evaluated and incorporated into the IRP process.

The Companies aim "to provide all customers, irrespective of income or other demographic criteria, with safe and reliable service at the lowest reasonable cost," but the Companies have not considered or performed any analysis of the impacts of the proposed

---

[8] 807 KAR 5:058.

Integrated Resource Plan on residential customers with low- or fixed- incomes.[9] In response to a request to explain this disconnect, the Companies opine that there is "neither a requirement nor authority to differentiate between low- and fixed-income customers and all other customers in an IRP."[10] Respectfully, the Companies are mistaken; their view is unsupported by law and logic.

1. The Companies' view is unsupported by law.

The Companies' view that they need not consider all customers' needs in the course of resource planning is unsupported by Kentucky law. The Companies do have an obligation to consider the needs of *all* customers—including low- and fixed-income customers. Monopoly utilities must provide adequate, efficient, and reasonable service,[11] implicitly requiring some understanding of service needs. The IRP regulation further invites an analysis of customer needs in multiple respects, and nowhere discourages utilities from considering the unique needs of low- and fixed-income customers. For example, load forecasting data is to be provided not only at the customer class level, but also at any greater level of disaggregation available;[12] and plan summaries must include descriptions of the utilities' customers and service territories, without limitation;[13]and include key economic and demographic assumptions or projections.[14]

---

[9] Response of Louisville Gas and Electric Company and Kentucky Utilities Companies to Joint Intervenors' Supplemental Discovery Requests, Question 2.8, *In the Matter of Elec. Application of Ky. Am. Water Co. for an Adjustment of Rates,* Case No. 2021-00393 (Mar. 25, 2022) (Response to JI Q").

[10] *Id.*

[11] KRS 278.030(2).

[12] 807 KAR 5:058(7)(1) (requiring historical and forecasted information regarding loads, provided by customer class or any greater level of disaggregation available).

[13] 807 KAR 5:058(5)(1).

[14] 807 KAR 5:058(5)(3).

To explain their rationale for not considering customer needs and impacts in this IRP, the Companies cite two authorities, but neither supports their position. First, the Companies offer that, in a 2005 Kentucky-American Water Company rate case, "the Commission stated that special low-income rates are not permissible,"[15] but this is not a rate case and establishment of low-income rates is not at issue. Rather, Joint Intervenors sought an explanation of how the Companies' IRP could possibly reflect the objective to provide all customers with safe and reliable service at the lowest reasonable cost, given that the Companies have not performed any analysis of how their projected resource decisions would impact customers, particularly low- and fixed-income customers.[16]

The Companies next refer to a three-page procedural order, issued January 3, 2019, in Kentucky-American Water Company's 2018 rate case, for the proposition that "affordability is not a factor that the Commission can consider . . . .",[17] as though that amounts to a jurisdictional bar against Kentucky utilities considering how low- and fixed-income customers are served or impacted by resource choices. It does not. Indeed, in that very same case, by the Commission's own request, Kentucky-American presented a witness able to discuss programs intentionally designed to assist low-income customers.[18] This is one among many instances where the

---

[15] Response to JI Q 2.8 ("Also, nearly two decades ago the Commission stated that special low-income rates are not permissible." (citing *Adjustment of the Rates of Ky. Am. Water Co.*, Case No. 2004-00103, Order at 82–84 (Ky. PSC Feb. 28, 2005)).

[16] *Id*.

[17] *Id.* (citing Order at 3, *In the Matter of Elec. Application of Ky. Am. Water Co. for an Adjustment of Rates*, Case No. 2018-00358 (Ky. PSC Jan. 3, 2019)).

[18] Order at 87, *In the Matter of Elec. Application of Ky. Am. Water Co. for an Adjustment of Rates*, Case No. 2018-00358 (June 27, 2019), https://psc.ky.gov/pscscf/2018%20Cases/2018-00358//20190627_PSC_ORDER01.pdf.

Commission and courts have considered the unique needs of low-income customers, including consideration of affordability as a critical consumer interest.[19]

Thus, while it is certainly true that the Companies did not particularly analyze the needs of their low- and fixed-income customers as part of their long-term planning exercise, Kentucky law neither requires nor excuses that decision.

2. The Companies' view is unsupported by logic and makes for bad planning.

In addition to being unsupported by law, the Companies' view that their customers' needs are irrelevant to long-term resource planning defies logic and makes for bad planning. Determining whether "all customers" are receiving safe and reliable service at the lowest reasonable cost requires some analysis of customers' needs and of how all customers—including low- and fixed-income residential customers—are impacted by resource decisions.

However, it seems the Companies cling to an antiquated view of their business in which all they do is generate, sell, and transmit electrons to customers. That approach may return profits to shareholders; but it cannot optimize the value returned to customers. Returning value to customers requires recognition of customers' unique needs and exploration of the full suite of energy resources and services capable of meeting those unique needs.

---

[19] *E.g., Ky. Indus. Util. Customers, Inc. v. Ky. Pub. Serv. Comm'n*, 504 S.W.3d 695, 705 (Ky. Ct. App. 2016) (observing that monopoly service "strips consumers of the right to price shop for the most affordable rates," leaving consumers dependent on the Commission to ensure affordability); *Nat'l–Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W.2d 503 (Ky. Ct. App.1990) (affirming Commission's consideration of affordability when it approved variable rates); Order at 1, *In the Matter of An Assessment of Ky.'s Elec. Generation, Transmission and Distrib. Needs*, Case 2005-00090, 2005 WL 612858 (Mar. 10, 2005) ("Residential consumers, particularly those with low or fixed incomes, depend on low electricity rates in order to afford other goods and service."); Order, *In the Matter of the Application Of Louisville Gas & Elec. Company to adjust its gas rates and to increase its charges for disconnecting service, reconnecting service and returned checks*, Case No. 2000-080, 2008 WL 1791791 (Sept. 27, 2000) (considering impact of disconnection and reconnection charge changes on low-income customers).

With respect to the needs of their low- and fixed-income residential customers, the Companies integrated no historical data into their planning exercise, and disregarded the correlation between customer usage and bill impacts; made no attempt to discern residential end-use trends across their service territories; provided no analysis of impacts from increasing costs of generation; provided no analysis of impacts from the preferred portfolio; offered no examination of potential for disparate economic impacts;[20] and made no use of available environmental justice screening tools.[21]

The Companies fail to acknowledge the distinction between rates and bills, and how usage patterns, driven by circumstances, can drive up *bills* for low-income customers, even when they share the same *rates* as their higher-income neighbors. For the customer, it is ultimately the size of their bills that matter—how much a household has to pay each month. While providing the same rates to all customers is one element in preventing unreasonable discrimination (as required by statute), ignoring demographic and historical data about customers leads to the perpetuation of inequities and missed opportunities.

With their question responses, the Companies make it clear that they do not recognize the connections between resource choices and customer needs or customer impacts. However, those connections clearly exist. For example, the Companies' IRP assumes in all scenarios that all existing energy efficiency and demand response programs, including the WeCare program, do

---

[20] Response of Louisville Gas and Electric Company and Kentucky Utilities Company to Joint Intervenors' Initial Discovery Requests, Question 1.2, *In the Matter of Elec. Application of Ky.-Am. Water Co. for an Adjustment of Rates,* Case No. 2021-00393 (Feb. 11, 2022) ("Response to JI Q").

[21] Response to JI Q 2.97.

not continue beyond 2025, and that program investment and energy savings cease thereafter.[22] If the Companies act consistently with that assumption, low-income customers will lose valuable weatherization support, leaving them with one less avenue to potentially lower their usage and their monthly bills, and forcing higher energy and demand needs to the system as a whole.[23]

In addition to illustrating the direct connection between resource decisions, customer need, and customer impact, the WeCare program also reflects the Companies' disparate impact problem. In the Companies' view, considering the unique needs and circumstances of low- and fixed-income customers in their service territories would be discriminatory[24]; but that view misses the potential for disparate impact when differently situated customers are treated as though they are the same. Differently situated customers will have different needs, which can be met via a diverse portfolio of resources and services.

Here in Kentucky, for example, the housing code did not require insulation in new buildings until the 1980s, and as a result, much of the housing stock built before the 1980s lacks

---

[22] 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume I, 2021 IRP Long-Term Resource Planning Analysis at Tbl. 8-12 ("2021 IRP, Vol. I") (showing incremental DSM savings of zero for all programs after 2025); *id.* at Tbl. 8-13 (showing cumulative DSM savings are flat or falling after 2025); *id.* at Tbl. 8-14 (providing DSM program costs for only 2019–2025).

[23] The Companies provided conflicting information on the continuation of the WeCare Program. Although no savings or costs from the program were included in the Companies' IRP analysis, in response to discovery, the Companies say they "expect to apply to continue the [WeCare] program" beyond 2025. Response to JI Q 1.2(j). At best, this is another example of the Companies not taking the IRP process seriously. The Companies' IRP should fully incorporate and analyze the actions LG&E/KU expect to take over the course of the planning period. In this instance, that means that costs and savings from the existing demand-side management programs that the Company may continue beyond 2025 are evaluated in the resource optimization modeling, under a methodology that puts those resources on equal footing with their supply-side counterparts.

[24] Response to JI Q 2.8.

insulation.[25] Without insulation, homes waste energy year-in and year-out, driving unnecessary costs to individual customers and the system as a whole. Publicly available reports have shown that most of these older homes are in predominantly low-income areas, often occupied by renters and people of color.[26] These facts reflect a structural inequity, borne of our history, and disproportionately drive up energy costs for low-income customers.

The Companies' WeCare Program, and other DSM programs dedicated to helping low-income customers reduce energy waste and control bills, help resolve this structural inequity to the benefit of customers, communities, and the state as a whole. On the other hand, if the Companies end the WeCare Program after 2025, (and fail to develop new, effective efficiency programs), and continue to plan their resource portfolio with disregard for the unique service needs of different groups of customers, low-income customers will continue to be disproportionately burdened.

B. Low- and Fixed-Income Customers face unique risks and have unique service needs.

In order to ensure that low- and fixed-income customers maintain energy access, it is important to consider their unique needs in the course of long-term planning, including affordability. Customer bills are driven by utility resource decisions, and bills are getting

---

[25] The first edition of the Kentucky Building Code was adopted in 1980 and based on the BOCA Basic Building Code 7th ed. *See generally* KRS Ch. 198B; 815 KAR Ch. 7.

[26] *E.g.*, Louisville Metro Government, Louisville Housing Needs Assessment at 53 (Feb. 2019), https://louisvilleky.gov/housing/document/hnafinal190222pdf ("Housing age varies greatly by market area. Homes tend to be oldest in Northwest Core, University, Southeast Core, and West Core, and while a newer housing stock exists in the eastern market areas."); Metropolitan Housing Coalition, 2020-2021 State of Metropolitan Housing Report at 23–27 (Aug. 2020), https://metropolitanhousing.org/wp-content/uploads/2021/08/MHC_2020_21_report_4_web_updated7-29-21.pdf (reporting housing segregation data for Louisville/Jefferson County and the Louisville MSA).

increasingly unaffordable. "Utility costs play an ever-increasing role in the overall expense of maintaining a household, and for many low-income families, represents a significant portion of their budget."[27] Median family income has not kept up with prices for basic utility services,[28] increasing pressures on household budgets and increasing energy insecurity, with many households unable to meet basic heating, cooling, and energy needs.[29] These pressures and insecurities are intensifying: Over just the last year, "inflation surged to a new four-decade high of 8.5% . . . driven by skyrocketing energy and food costs, supply constraints and strong consumer demand."[30]

Generally, we know that lower-income families are most likely to experience energy insecurity, making them more likely to: "(1) live in housing with heating and electrical problems, (2) have experienced multiple heating equipment breakdowns, (3) have had an interruption in utility service, (4) have inadequate insulation and insufficient heating capacity, and (5) report being uncomfortably cold for more than 24 hours during the winter."[31] These well-known

---

[27] Metropolitan Housing Coalition, 2014 State of Metropolitan Housing Report: A Look Back, A Look Forward at 7 (2014), https://metropolitanhousing.org/wp-content/uploads/2020/10/CORRECTED-WITH-ALL-DONORS-2014-SMHR-12-10-14.pdf.

[28] *Id*. at 7; Metropolitan Housing Coalition, 2008 Metropolitan Housing Report at 2 (2008), https://metropolitanhousing.org/wp-content/uploads/2020/10/2008_State_of_Metropolitan_Housing_Report.pdf.

[29] Diana Hernández et al., Energy Insecurity among Families with Children, Nat'l Center for Children in Poverty (Jan. 2014), https://www.nccp.org/wp-content/uploads/2020/05/text_1086.pdf.

[30] Gwynn Guilford, U.S. Inflation Accelerated to 8.5% in March, Hitting Four-Decade High: Consumer-price index increase from year earlier driven by skyrocketing energy and food costs, Wall Street Journal (Apr. 13, 2022), https://www.wsj.com/articles/us-inflation-consumer-price-index-march-2022-11649725215.

[31] Diana Hernández et al., Energy Insecurity among Families with Children, Nat'l Center for Children in Poverty (Jan. 2014), https://www.nccp.org/wp-content/uploads/2020/05/text_1086.pdf.

markers of energy insecurity are disproportionately weathered by lower-income families, Black families, and Hispanic/Latino families.[32]

The national pattern of increasing insecurity, disproportionately faced by low-income households and minority households, is all too present in LG&E/KU's service territory. In Louisville/Jefferson County, 14.2% of residents live below the federal poverty line—higher than the national rate of 13.4%. Income has been somewhat static, with Kentucky's average annual household income increasing by just a few hundred dollars over the last decade.[33] In these circumstances, housing insecurity remains a significant and persistent local issue, with reported eviction rates often above the state average in Louisville and Jefferson Counties.[34] All the while, energy costs managed significant increases. In Kentucky, over the last twenty years, the average retail price of electricity for residential customers has increased from just over $0.05/kWh to nearly $0.12/kWh.[35]

In concert, static wages with ever-increasing utility costs means households are paying an ever-larger percentage of income toward energy needs. The U.S. Department of Housing and Urban Development long ago observed that households paying more than 30% of income on

---

[32] *Id*. at 5.

[33] Comparing 2010 and 2020 United States Census Bureau American Community Survey Data, 5-Year Estimates Subject Tables.

[34] Metropolitan Housing Coalition, 2020-2021 State of Metropolitan Housing Report: COVID-19 and the Struggle to Stay Safe at Home in Louisville, KY (Aug. 2021), https://metropolitanhousing.org/wp-content/uploads/2021/08/MHC_2020_21_report_4_web_updated7-29-21.pdf (reporting 2020 eviction rate of 5.4%, which reflects relief efforts to avoid mass evictions during a public health crisis and amounts to a dramatic decline from the 2016 eviction rate of greater than 14%).

[35] Form EIA-861 Annual Survey Data; *see also* Kentucky Department of Energy Development and Independence, Kentucky Energy Profile 2010 at 37 (2010) (reporting residential rates in 2009 of $0.0731 and $0.0758 for Kentucky Utilities and Louisville Gas and Electric Company, respectively).

gross housing—including utility expenses—have an excessive housing burden; and within that, utility bills higher than 6% of income represent excessive energy burdens.[36] When budgets are strained in this way, households must make very difficult choices between necessities: heat or eat? Pay the rent or the utility bill? Face disconnection, eviction, or hunger? This is the reality for some of the Companies' customers. In Louisville/Jefferson County, for example, the Department of Energy's Low-Income Energy Affordability Data Tool ("LEAD Tool") reports an average 9% energy burden for households at or under 200% of the federal poverty level; in Fayette county, households at or under that same threshold experience an average energy burden of 8%; and in Bell and Harlan counties, similar households experience an average energy burden of 11%.[37]

For LG&E/KU customers facing housing and energy insecurity, utility investments in reducing energy waste, increasing energy efficiency, and improving customer resilience are a win-win opportunity for the utility, their customers, and the community. The value to customers from these demand-side resource investments goes far beyond their relatively low-cost compared to supply-side resources. Demand-side resource investments provide tangible benefits to customers and communities by reducing energy bills and the burdens of poverty; reducing disconnections; helping families avoid eviction and stay in their homes; and creating healthier homes, all while reducing overall system costs and system risks.[38]

---

[36] *E.g.*, Fisher, Sheehan & Colton, Home Energy Affordability Gap, (2013), www.homeenergyaffordabilitygap.com.

[37] Office of Energy Efficiency & Renewable Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool (last accessed Apr. 22, 2022) (LEAD Tool is an interactive platform intended to "help stakeholders understand housing and energy characteristics for low- and moderate-income households.").

[38] The experience of People's Self-Help Housing, Inc. in Vanceburg, Kentucky demonstrates the importance of energy efficiency in enabling lower-income families to stay in their homes. A fact

C. Grounding the IRP in analysis of customers' needs enables identification of portfolios that are lowest cost and optimize customer value.

It is with this context in mind that Joint Intervenors encourage LG&E and KU to include detailed consideration of all customers' needs and assessment of impacts to all customers in its future IRPs—particularly including residential customers with low- or fixed-incomes. Without that grounding, as in the Companies' 2021 IRP, there is insufficient context to balance the trade-offs in cost, risk, and customer value presented by different resource portfolios. LG&E/KU claim to be adequately serving all customers, but without an analysis of customer needs and consideration of customer impacts flowing from different resource choices, that claim is not only unsubstantiated, but flies in the face of reality, in which utility costs add to the burden of poverty for many customers of LG&E/KU.

In addition to the WeCare example discussed above, the Companies neglect of demand-side resources generally in this IRP reflects a disregard for customer needs and customer value, as addressed in Section III.

Another missed opportunity can be found in the Companies' consideration of DERs. In Figure 5-13 of IRP Vol. I, the Companies acknowledge potential for a significant build-out of distributed solar resources in its service territories. In the Companies' analysis, that potential is realized only after a triggering assumption that "a new federal law is assumed to eliminate the

---

sheet about PSHH's Evergreen housing development reports that the development contains twenty-seven affordable, energy-efficient homes for low-income families. The average Evergreen home is 63% more energy-efficient than the standard new home. According to PSHH, "Low utility bills are an important part of keeping homes affordable for many years to come for homebuyers with limited incomes." Fact Sheet, People's Self-Help Housing, Inc. (2018)

1% cap on total installed net metering capacity."[39] Fortunately, no federal action is needed as there is no such cap.[40]

Rather, by statute, Kentucky utilities have the *discretion* to continue offering net metering service once the cumulative installed capacity of net metering customers reaches 1% of the utilities' annual peak load, and there is no requirement to stop offering net metering:

> KRS 278.466 (1) Each retail electric supplier shall make net metering available to any eligible customer-generator that the supplier currently serves or solicits for service. If the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year, the supplier **shall have no further obligation** to offer net metering to any new customer-generator at any subsequent time.[41]

Thus, it is within the Companies' power and discretion to offer net metering to any new customer-generator regardless of the percentage of peak load already participating in net metering.[42]

As part of their Integrated Resource Planning exercise, the Companies could have evaluated the potential for allowing greater participation in net metering to reduce the need for new utility-funded generation builds or to accelerate the retirement of relatively expensive and polluting units.[43] The IRP itself alludes to this potential in Figure 5-15 (p.5-30 of Vol. I), which shows the peak energy savings net metering could provide to the Companies, if allowed to grow

---

[39] 2021 IRP, Vol. I at 5-29.

[40] KRS 278.466.

[41] KRS 278.466(1) (emphasis added).

[42] *Id.*

[43] *E.g.*, Order at 21–22, *In the Matter of Elec. Application of Ky. Power Co. for a Gen. Adjustment of Its Rates for Elec. Serv.*, Case No. 2020-00174 (May 14, 2021), https://psc.ky.gov/pscscf/2020%20Cases/2020-00174//20210514_PSC_ORDER.pdf ("Because eligible customer-generators and their eligible generating facilities can meet power system needs, they should be compared with other energy resources using consistent methods, processes, and assumptions.").

unconstrained by the 1% “cap.” Figure 5-15 indicates the potential for about 500 MWh of reduced energy requirements for one day in August. This reflects the substantial potential for DERs to serve as a system resource and the importance of including them on equal footing with traditional supply-side resources in the IRP analysis. In addition to reducing the overall cost to customers, supporting DERs in this manner also returns value to customers by increasing energy security and resilience, creating local jobs, and reducing emissions and expenses associated with fossil generation.[44]

D. Recommendations for data and analysis to support a greater understanding of customer needs and customer impacts.

Joint Intervenors urge the Companies to integrate more fulsome analysis of unique customer needs and discussion of customer impacts in future IRPs. Going forward, LG&E/KU’s triennial Integrated Resource Planning exercise should include reporting and assessment of trends impacting service to low- and fixed-income customers, and those trends should inform analysis of portfolios. Data that could help characterize how low- and fixed-income customers are faring could include the following:

- Average energy burdens and percent of households in each census tract with excessive energy burdens (i.e., at or above 6%)
- Number, frequency, and age of unpaid bills (indicating energy insecurity)
- Number of monthly disconnect notices and disconnections (indicating energy insecurity)

[44] *See generally*, National Energy Screening Project, National Standard Practice Manual: For Benefit-Cost Analysis of Distributed Energy Resources (Aug. 2020) (“NSPM-DER”).

- Number of residential account transfers to new addresses (indicating housing instability)
- Amount of bad debt (indicating energy insecurity)
- Number of households on repayment plans
- Average length of disconnections for non-payment
- Census tracts with the highest incidence of disconnection notices and actual disconnections
- Census tracts with the highest usage intensity

In addition to the types of data above, the Companies should also avail themselves of public data sources capable of filing in gaps. Relevant public data sources would include U.S. Census American Community Survey Data, the Department of Energy's Low-Income Energy Affordability Data Tool, Louisville Metro Center for Health and Equity's Healthy Equity Report, 2020 Analysis of Impediments to Fair Housing Choice in Louisville Metro, Kentucky, and Annual State of Metropolitan Housing Reports. Publicly available data from these sources can help the Companies to better understand customer needs.

With that grounding, the Companies Integrated Resource Planning exercise will be capable of assessing the trade-offs in customer value that come with different demand- and supply-side resource alternatives. If the Companies are looking for ways to evolve, adapt, and best meet customer expectations,[45] pursuing this sort of truly *Integrated* Resource Planning is one such opportunity.

---

[45] Thompson Direct at 7, ("[T]here are opportunities for the Companies to evolve and adapt by continually recognizing and evaluating changes in our industry, technology and customer expectations.")

III. The Companies' limited examination of energy efficiency and demand side management undermines the Integrated Resource Planning exercise.

The Companies' examination of demand-side resources in its long-range planning exercise was insufficient. That was the case despite explicit direction in the IRP regulations to explore expanded demand-side resource options, despite the claimed successes of the Companies' past energy efficiency and demand response programs, and despite the incredible potential to cost-effectively serve customers by being a partner in reducing energy waste, increasing energy efficiency, and reducing system peak demands.

A. Commission regulations and orders plainly require an analysis of expanded demand-side management programs.

The Companies cannot dispute that, throughout the time spent working on their Integrated Resource Planning exercise, they were aware of requirements to fully examine future demand-side resources. Yet, the Companies undertook no such analysis, flouting those requirements.

The requirement to consider demand-side resources has long been obvious on the face of the Commission's IRP regulations. The Companies were required, by 807 KAR 5:5058(2)(b), to provide a description of "conservation and load management or other demand-side programs not already in place"; by 807 KAR 5:058(3)(e) to provide information on each "existing and new conservation and load management or other demand-side programs included in the plan"; by 807 KAR 5:058(4)(b)(5), to include information in the acquisition plan that takes into account reductions from new conservation and load management or other demand-side programs; and by 807 KAR 5:058(5)(c), to discuss criteria used to screen potential demand-side programs.

Making the Companies' obligations even more plain, the Commission and Commission Staff have repeatedly stressed the importance of evaluating demand-side resources. In 2021, the

Commission required the Companies "to begin evaluating possible DSM programs that will add low-cost value and assist in avoiding the high cost of building new generation."[46] It was unreasonable to exclude expanded DSM resources in this IRP, particularly considering the potential cost-effectiveness of those resources.[47]

B. Energy efficiency is the least-cost resource available to the Companies.

The cheapest kilowatt hour is the one that does not need to be generated: The industry-wide levelized cost of energy savings from utility efficiency investments has been calculated as roughly $0.0240 to $0.0280 per kilowatt hour saved (or $24 to $28 per megawatt hour saved).[48] That levelized cost compares quite favorably to the gas peakers centered in the Companies' resource planning, which Lazard estimates carry a levelized cost of energy of $151 to $196 per megawatt hour—or even higher given their sensitivity to fuel prices.[49] In fact, the levelized cost

---

[46] Order at 61, I*n the Matter of Elec. Application of Ky. Util. Co. for an adjustment of Its Elec. Rates*, Case No. 2020-00349 (June 30, 2021), https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210630_PSC_ORDER.pdf; Order at 22–23, *In the Matter of Elec. 2018 Joint Integrated Resource Plan of Louisville Gas and Elec. Co. and Ky. Util. Co.*, Case No. 2018-00348 (July 20, 2020), https://psc.ky.gov/pscscf/2018%20Cases/2018-00348//20200720_PSC_ORDER.pdf.

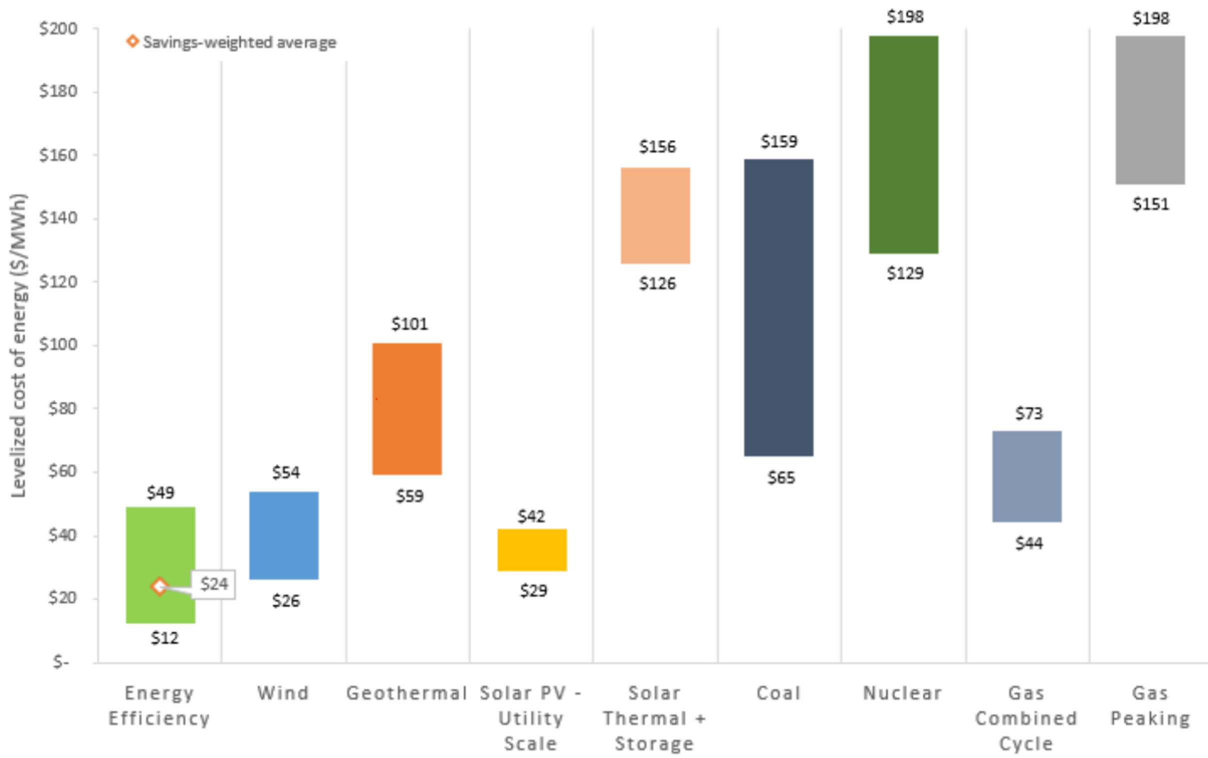
[47] 807 KAR 5:058(8)(1) ("The plan . . . shall include assessment of potentially cost-effective resource options available to the utility.").

[48] Maggie Molina, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, ACEEE, 18–19 (Table 3 showing $0.0280/kWh) (Mar. 2014), https://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf; Charlotte Cohn, The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-Funded Efficiency Programs in 2018, ACEEE: Policy Brief, 1 (June 2021), https://www.aceee.org/sites/default/files/pdfs/cost_of_saving_electricity_final_6-22-21.pdf. (showing $0.0240/kWh).

[49] Lazard, Lazard's Levelized Cost of Energy Analysis—Version 15.0 at slides 2 and 4 (Oct. 2021), https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.

of savings from utility efficiency investments compares favorably to all the resources in Lazard's levelized cost of energy comparison, as shown in Figure 1 below.[50]

Figure 1: Levelized cost of energy resources[51]



In addition to being relatively low-cost, efficiency investments return value to customers by reducing their energy waste, thereby lessening overall usage and overall bills. It is a win-win-win, but the Companies ignored it in favor of an exclusive focus on building expensive new

---

[50] *Id.* (utility-scale wind and solar resources compare favorably to energy efficiency, but only upon inclusion of federal tax subsidies).

[51] Charlotte Cohn, The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-Funded Efficiency Programs in 2018, ACEEE: Policy Brief, 9 (June 2021), https://www.aceee.org/sites/default/files/pdfs/cost_of_saving_electricity_final_6-22-21.pdf.

supply-side generating capacity. Such an approach could perhaps maximize shareholder return on investment; but is less likely to optimize value to customers.

C. Demand-side programs offer tremendous untapped potential for the Companies and their customers.

As told by the Companies, their "DSM-EE programs have been a tremendous success."[52] Through September 2021, the Companies' DSM-EE programs produced cumulative energy savings of approximately 1,410 GWh and reduced gross demand by over 486 MW.[53] The Companies' current DSM-EE programs were approved in Case No. 2017-00441 to continue through 2025, with the Companies projecting energy savings of approximately 215 GWh and reduced demand of 179 MW.[54] Current programs are already exceeding expectations, with higher than expected program participation in the Non-Residential Rebate Program.[55]

These past savings likely represent just a fraction of the cost-effective efficiency savings available in the Companies' service territory. Utilities across the country have succeeded in developing energy efficiency programs achieving annual energy savings above 1% of retail sales, with a handful of utilities achieving net energy savings above 2% of sales.[56] For LG&E/KU, with Kentucky retail load of 17,176 GWh in 2020,[57] achieving net savings of 1%

---

[52] 2021 IRP, Vol. I at 8-19.

[53] *Id.*

[54] *Id.* at 8-27.

[55] Response of Louisville Gas and Electric Company and Kentucky Utilities Company to Commission Staff's Supplemental Discovery Requests, Question 1.4(a), *In the Matter of Elec. Application of Ky.-Am. Water Co. for an Adjustment of Rates*, Case No. 2021-00393 (Feb. 11, 2022) ("Response to Staff Q")

[56] American Council for an Energy-Efficient Economy, 2020 Utility Energy Efficiency Scorecard at Tbl. 8 (Feb. 2020) (reporting scores for net savings as a percentage of retail sales in 2018 among selected utilities).

[57] 2021 IRP, Vol. I at Tbl. 7-3.

would represent 171,760 MWh—considerably more than the annual 30,894 MWh of energy savings anticipated under the Companies' existing programs.[58]

But the Companies "did not directly evaluate new demand-side management ("DSM") programs in this IRP."[59] Despite the clear requirements to consider demand-side resources in their *Integrated* Resource Planning, "[t]he Companies did not evaluate any specific programs . . ." in their long-term planning exercise.[60] The Companies did not even evaluate the implications of continuing their existing energy efficiency and demand response programs beyond 2025, instead assuming zero energy and demand savings after 2025. Assuming zero energy and demand savings after 2025 serves only to unreasonably inflate the amount of new generation capacity that the IRP assumes the Companies will need.

The Companies know that energy and demand savings can reduce the need for investment in new generation: in fact, they've managed exactly that through past demand-side programs. For example, through the Residential Demand Conservation program, customers have empowered the Companies to control over 230,000 electrical devices, totaling 100 to 150 MW of load on a hot summer day, or "roughly equivalent to investing in a peaking combustion

[58] *See* Direct Testimony of Gregory S. Lawson, Ex. GSL-1 at Tbls. 4-2, 4-5, and 4-8, *In the Matter of: Elec. Joint Application of Louisville Gas and Elec. Co. and Ky. Util. Co. for Review, Modification, and Continuation of Certain Existing Demand-Side Mgmt. and Energy Efficiency Programs*, Case No. 2017-00441 (Dec. 6, 2017), https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.GSL-1

[59] 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Volume III, Resource Plan Technical Appendix, 2021 IRP Resource Screening Analysis at 13 ("2021 IRP, Vol. III").

[60] Response to JI Q 1.38(d).

turbine."[61] The success of that program, and the Small Nonresidential Demand Conservation Program are elsewhere touted to "provide economic and environmental benefits by delaying the need to construct new generation assets"[62] These statements from the Companies show that they do understand the potential for demand-side resources to out-compete new supply-side resources.

D. The failure to evaluate cost-effective demand response and energy efficiency resources throughout the planning period undermines the IRP.

In light of claimed successes with demand response and energy efficiency programs and clearly stated regulatory requirements, it is confounding that the Companies would exclude potentially cost-effective demand-side resources in their Integrated Resource Planning exercise. The Companies apparent bias in favor of supply-side resources in this IRP was unreasonable, with ripple effects that undermine the entire exercise.

As addressed above, energy efficiency and demand response programs return significant value to customers relative to their supply-side counterparts. When the Companies invest in new gas generation, customers are burdened by a range of negative consequences (in addition to higher costs): pollution increases, air quality decreases, our global climate is destabilized. In contrast, effective energy efficiency and demand response investments deliver only positives: reduced energy waste and improved efficiency reduces consumption and overall customer bills; efficient homes are more safe, comfortable and resilient; and system-wide energy and peak demand needs are reduced—avoiding costly future investments and reducing reliance on the

---

[61] Direct Testimony of Gregory S. Lawson, Ex. GSL-1 at 45, *In the Matter of: Elec. Joint Application of Louisville Gas and Elec. Co. and Ky. Util. Co. for Review, Modification, and Continuation of Certain Existing Demand-Side Mgmt. and Energy Efficiency Programs*, Case No. 2017-00441 (Dec. 6, 2017), https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

[62] *Id.* at 46.

Companies dirty generation resources. The reduced emissions from saved energy also provide public health benefits, which the Environmental Protection Agency estimates have value in the range of 2.70 to 6.10 cents per kilowatt hour saved.[63]

In the Companies' telling, their decision to assume zero energy and demand impacts from their DSM programs after 2025 is reasonable because the Commission has yet to approve continuation of those programs past that date: "The current DSM Portfolio is currently only approved through the end of 2025, which is why there are not projections for incremental energy and demand impacts beyond this date."[64] This makes no sense. In large part, the purpose of Integrated Resource Planning is to consider the relative costs and risks of not-yet-approved resources throughout a long-term planning period. Just as it was obvious to the Companies that not-yet-approved supply-side resources should be incorporated into their IRP modeling, so too should they have recognized the importance of modeling not-yet-approved demand-side management programs.

Further, shortcomings in past analyses do not justify a weak analysis of demand-side resources in this IRP.[65] The Companies should commit to modeling demand- and supply-side resources on equal footing in their next IRP. That unbiased analysis is necessary to identify a

---

[63] Environmental Protection Agency, Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report, 2nd ed., at Tbl. ES-1 (May 2021), https://www.epa.gov/sites/default/files/2021-05/documents/bpk_report_second_edition.pdf (applying peer-reviewed methodology and tools to develop screening level regional estimates of benefits per kilowatt-hour from energy efficiency and renewable generation).

[64] Response to JI Q 1.14.

[65] *Contra* Response to Staff Q 1.4(a).

least-cost plan and required by regulation.[66] To assist, the EFG Report provides specific recommendations explaining how utilities routinely evaluate different levels of demand-side savings in resource optimization modeling.[67]

E. Following best practices for evaluating benefits and costs of demand-side resource potential.

Joint Intervenors recommend that the Companies apply principles from the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM-DER"), which offers a comprehensive framework for cost-effectiveness analysis of distributed energy resources, including energy efficiency, demand response, and distributed storage and generation.[68] The NSPM-DER "provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources."[69] Recently, the Commission applied the following principles from the NSPM-DER to evaluation of Kentucky Power Company's net metering tariff, *inter alia*: treating benefits and costs symmetrically; conducting forward-looking longer term and incremental analyses; avoiding double counting; and ensuring transparency.[70]

---

[66] 807 KAR 5:058(8)(2)(b); *see also Re Present & Future Elec. Needs & Alternatives for Meeting Those Needs*, 120 P.U.R.4th 143 1990 WL 488967 (Ky.P.S.C. Aug. 8, 1990) (adopting IRP regulations with stated goal to establish "a process to review and analyze all options available for meeting the state's electricity needs . . .").

[67] Ex. 1, EFG Report at section 3.6.1.

[68] NPSM for Benefit-Cost Analysis of Distributed Energy Resources (Aug. 2020), https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/ ("NSPM-DER").

[69] NSPM-DER at i.

[70] Order at 21–24, *In the Matter of Elec. Application of Ky. Power Co. for a Gen. Adjustment of Its Rates for Elec. Serv.*, Case No. 2020-00174 (May 14, 2021).

Although the Companies have argued that they view these principles as applying exclusively to compensation for net metering customers,[71] it is logical to consider that if the Commission found them to be reasonable for the evaluation of one type of distributed energy resource (net metering), they would be useful in the evaluation of other DERs, as well. The NSPM-DER was specifically written to provide best practices for evaluating a wide range of DERs, and it would be reasonable for the Companies to consult such best practices within the IRP process.[72]

F. Investments in customer efficiency savings can be scaled-up by employing Pay-As-You-Save Programs.

Joint Intervenors further recommend that the Companies examine the cost and value of increased energy efficiency investments and specific energy savings targets. That exploration should include consideration of Pay-As-You-Save ("PAYS") Programs. PAYS Programs could contribute to the Companies' goal of offering safe, reliable, and least-cost energy to customers, as detailed in the attached report from expert James Owen (Exhibit 2), which is incorporated in these comments in its entirety. Mr. Owen explains the relative cost-effectiveness of a PAYS Program compared to the Companies' existing fossil-heavy portfolio, finding potential for significant savings.[73] PAYS programs reduce barriers to customer adoption of demand-side management resources and barriers to participation in utility-sponsored DSM programs by

---

[71] Response to JI Q 2.84.

[72] NSPM-DER at i (explaining applicability to energy efficiency and demand response, among other DERs); Order at 24, *In the Matter of Elec. Application of Ky. Power Co. for a Gen. Adjustment of Its Rates for Elec. Serv.*, Case No. 2020-00174 (May 14, 2021).

[73] Ex. 2, PAYS Report at ¶3.

providing customer access to low-cost capital.[74] This access to capital can be especially critical to low- and fixed-income customers, enabling broader participation in DSM programs and reducing system energy and demand needs.[75] PAYS Program investments in excess of $50 million have been made across ten states, including being offered by every investor-owned utility in the state of Missouri and several rural electric cooperatives in Kentucky.[76]

Adopting these recommendations—analyzing demand-side resources on equal footing with supply-side resources, fully accounting for the value of demand-side resources and examining untapped programmatic approaches and potential—is critical to identifying a least-cost portfolio of resources.

IV. The Companies failure to evaluate climate risks further undermines the IRP.

As the for-profit stewards of our public electric utilities, the Companies need to better evaluate risks to their business and their continued ability to deliver an essential service at fair, just and reasonable cost. It should be unacceptable that the Companies did not attempt to evaluate the risks of different resources and portfolios in their Integrated Resource Planning exercise. Here, Joint Intervenors focus on the Companies' failure to integrate consideration of environmental risks in particular, but the animating principles apply equally to all risk factors.

The Companies unreasonably failed to consider the potential impacts of future carbon regulation, a key uncertainty given their carbon-intensive resources and future plans. The Companies' existing and planned generation significantly depend on generation from fossil fuels, which causes carbon emissions at each generating unit and upstream carbon emissions from the

---

[74] *Id.* at ¶5–7.

[75] *Id.*

[76] *Id.* at ¶¶6–8.

extraction and transport of coal and gas. This dependence presents a significant cost risk that the Companies almost entirely neglected in their long-term resource planning exercise. Unless the Companies' shareholders intend to indemnify customers against carbon price risks, that risk should be transparently assessed in the Companies triennial Integrated Resource Plans.[77]

The Companies are certainly capable of quantifying carbon price risks. The ready availability of methodologies capable of quantifying carbon price risks in resource planning cannot be disputed, particularly considering that the Companies themselves applied one such methodology in their 2018 IRP. At the time, LG&E/KU considered analysis of "Future CO2 risks/uncertainties" to be a "key issue" in the IRP.[78] To evaluate that key issue, the Companies tested portfolio sensitivity to future carbon emission prices, assuming a price per ton beginning in the year 2026.[79] Elsewhere, the Companies have not only evaluated carbon emissions, but also professed to do so as a matter of routine.[80]

---

[77] PPL Corporation acknowledged the financial and operational risks posed by carbon emissions in its recent climate report. PPL Corp., Energy Forward: PPL's 2021 Climate Assessment Report at 13–16 (Jan. 2022), https://www.pplweb.com/wp-content/uploads/2022/01/PPL_Corp-2021-Climate-Assessment_2022-01-04.pdf. Although LG&E/KU did not evaluate carbon as part of their 2021 IRP, PPL's plan for mitigating those financial risks does explicitly contemplate recovery of extraordinary climate-related capital costs from Kentucky customers. *Id.* at 16.

[78] *See* Louisville Gas and Electric Company and Kentucky Utilities Company, 2018 IRP Presentation at 12, Case No. 2018-00348 (Sept. 4, 2020), https://psc.ky.gov/pscecf/2018-00348/kendrick.riggs%40skofirm.com/09142020035419/LGE-KU_Ltr_Attaching_Informal_Conference_Presentation_9-14-20.pdf.

[79] 2018 Joint Integrated Resource Planning of Louisville Gas and Electric Company and Kentucky Utilities Company, Vol. I at 5-24.

[80] *E.g.*, Hearing Transcript at 9:39:53 to 9:40:19, *Elec. Application of Ky. Utils. Co. for an Adjustment of its Elec. Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349 (Apr. 28, 2021), https://www.youtube.com/watch?v=MOS7HXLjTM8 (Companies' Witness Conroy: "I wouldn't consider those [greenhouse gas emissions] externalities as we're talking about here. I mean, part of our own evaluation we always look at carbon emissions and other regulations and sensitivities.").

Given this history, we know the Companies could have evaluated carbon price risk exposure of the various portfolios considered in the 2021 IRP. But apart from adopting NREL's assumption that new combined cycle gas plants could no longer be assured of acquiring federal air permits without carbon capture capabilities, the Companies' offered no quantification of carbon price risks.

The Companies' failure to incorporate carbon price risk in their resource planning was a significant mistake, undermining the validity of the entire exercise. This mistake is puzzling, given that the Companies do sometimes take their contributions to greenhouse gas ("GHG") emissions seriously, including a commitment by their parent company to reach net-zero emissions by 2050;[81] and the Companies do identify "changes to environmental regulations" as a "key issue" potentially impacting their resource plan.[82] Contemplated changes in environmental regulations include efforts to mitigate greenhouse gas emissions:

> EPA is considering rulemaking proposals to address sources of climate- and health-impacting emissions. EPA states that these efforts include investigating the possibility of lowering the GHG [New Source Performance Standards] levels for new, modified, and reconstructed electric generating units, including new [Natural Gas Combined Cycle] units, as well as developing strategies to achieve reductions in GHG emissions from existing power plants. Depending on how far those efforts are taken, carbon capture, utilization, and sequestration ("CCUS") technologies may be needed to achieve desired reductions.[83]

The Companies continue to acknowledge that the federal government "has placed a high priority on climate change and GHG issues," and assert that they "will continue to follow all these GHG

[81] *E.g.*, PPL Corp., Energy Forward: PPL's 2021 Climate Assessment Report (Jan. 2022), https://www.pplweb.com/wp-content/uploads/2022/01/PPL_Corp-2021-Climate-Assessment_2022-01-04.pdf.

[82] 2021 IRP, Vol. I at 5-44 (Section 5.(6) Key Issues that Could Affect Plan Implementation).

[83] 2021 IRP, Vol. I at 6-11.

issues and assess their impacts on operating facilities."[84] Yet, beyond narrative, the Companies did nothing to test empirically the cost and operational risks of continued reliance on fossil fuels and fossil generation throughout the planning period considered in this IRP.

Prudent and reasonable Integrated Resource Planning must explore the GHG risks of various portfolio options.[85] This is especially true for LG&E and KU. Owing to the carbon-intensive nature of the Companies' existing portfolio, future regulation of carbon or establishment of a price or tax on greenhouse gas emissions could have devastating cost implications for customers. In 2021, the Companies estimate direct emissions of 29.8 million short tons of carbon dioxide, and via response to questions from Commission Staff, they acknowledge that, imposition of a "$15/ton and $25/ton carbon dioxide price would increase costs to customers by $447 and $746 million per year, respectively."[86]

That is a considerable cost risk that should have been better incorporated into the Companies' long-term resource planning analysis. Providing this information only in response to discovery is inadequate, first and foremost, because such risks should be part of the integrated analysis and a factor in resource evaluations. Secondly, by only providing this information

---

[84] *Id.*

[85] *See, e.g.,* Integrated Resource Planning Report, Vol. A at 78*, Elec. 2019 Integrated Resource Planning Report of Ky. Power Co.*, Case No. 2019-00443 (filed Dec. 20, 2019) (explaining how analysis of carbon emission was incorporated in IRP modeling: "[t]he Fundamentals Forecast employs a CO2 dispatch burden (adder) on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per ton commencing in 2028. This CO2 dispatch burden is a proxy for the many pathways CO2 may take (e.g., renewables subsidies/penetration, voluntary and mandatory portfolio standards, exceptionally low natural gas prices, considerable reduction in battery storage costs) in addition to any regulation to impose fees on the combustion of carbon-based fuels.")

[86] Response of Louisville Gas and Electric Company and Kentucky Utilities Company to Commission Staff's Supplemental Request for Information, Question 2.1(b) ("Response to Staff Q").

through discovery (as opposed to inclusion in the initial IRP filing) stakeholders are less able to fully consider the information during the IRP review period.[87] It must also be remembered that *avoided* carbon emissions have value, as the Commission recognized when it established its methodology for evaluating the avoided cost of net metering for distributed solar installations.[88]

There is no barrier—jurisdictional or otherwise—to this Commission requiring analyses of emissions risks facing Kentucky's monopoly utilities. Far from it, the Commission's duty to ensure fair, just and reasonable rates today and into the future demands a clear signal to monopoly utilities that robust risk analyses, including emission risks in particular, should be included in every IRP. As the Companies' themselves demonstrated, imposition of carbon regulation or a carbon price could increase their annual revenue requirement by hundreds of millions of dollars, year after year.[89] It is reckless for utility management to disregard such risks, and the Commission's duty to ensure they do not.

---

[87] EFG Report, Ex. 1, Sections 1 and 3.5.

[88] *E.g.*, Order, *Elec. Application Of Ky. Power Co. for (1) A General Adjustment of its Rates for Elec. Serv.; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Pub. Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174 (May 14, 2021) (recognizing value of avoided carbon costs among benefits of rooftop solar installations); Joint Post-Hearing Brief of the Kentucky Attorney General and the Kentucky Industrial Utility Customers, Inc. at 2, *Elec. Application of Ky. Utils. Co. for an Adjustment of its Elec. Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349 (May 24, 2021) ("It is no secret that because of heightened concern of CO2, Kentucky's predominately coal-fired generation fleet is at risk.").

[89] Response to Staff Q 2.1(b).

V. Limitations of the Companies' Regional Transmission Organization membership analysis.

The Companies are required to include a Regional Transmission Organization ("RTO") Membership Analysis with this IRP, and updated analyses in conjunction with each future rate case.[90] After reviewing the Companies' 2018 IRP, Commission Staff recommended that future IRPs provide comprehensive and detailed cost-benefit analyses of joining PJM or MISO, including all potential benefits and costs.[91] The RTO Membership Analysis accompanying the Companies' 2021 IRP falls short of that expectation.

To cite just one shortcoming of the Companies' RTO analysis, they did not include a carbon price in any of their analyses in order to compare the net benefit of remaining independent against the cost of RTO membership. Their justification for this substitutes a simplistic assumption for the rigorous analysis which should underpin the utilities' long-term planning processes: "*Assuming the carbon price was applicable both inside and outside an RTO, the Companies do not anticipate that it would have a meaningful impact on the overall analysis.*"[92] However, if there were a carbon price, and being in an RTO provided greater access to low-cost, low-carbon resources, this could very well shift the cost-benefit analysis in favor of joining the RTO.

Joint Intervenors support the observations and analysis provided by the Southern Renewable Energy Association's comments in this proceeding. Joint Intervenors agree that more

---

[90] Feb. 18, 2021 Order, Case No. 2018-00294.

[91] Order, Appendix at 41, *Elec. 2018 Joint Integrated Resource Plan of Louisville Gas and Elec. Co. and Ky. Utils. Co.*, Case No. 2018-00348 (Ky. PSC July 20, 2020), https://psc.ky.gov/psc scf/2018%20Cases/2018-00348//20200720_PSC_ORDER.pdf.

[92] Response to Staff's Q 2.7 (emphasis added).

comprehensive recognition of potential benefits is needed in the RTO Membership Analysis. We agree that more data-sharing with and participation by RTOs could lead to a more robust and reliable evaluation of RTO membership for the Companies.

CONCLUSION

Joint Intervenors appreciate this opportunity to provide comments and recommendations related to LG&E/KU's 2021 IRP. As set out in these comments and supporting expert reports, this IRP regrettably does not adequately evaluate all potentially cost-effective resource options and does not provide the level of analysis needed to compare portfolio performance and cost across time, under varied future conditions. In order to ensure that rates remain fair, just, and reasonable, closer examination of resource decisions is needed—including economic retirement horizons and prudent new resource investments on both sides of the meter. This can be achieved in the Companies' next IRP by better grounding the process in an understanding of customer needs and customer impacts, by adopting the recommendations in the EFG Report and PAYS Report, and by better quantifying and responding to business risks, especially those presented by climate change and the inevitable and necessary transition to a net-zero carbon economy.

Respectfully submitted,

Tom FitzGerald
Ashley Wilmes
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602
(502) 551-3675
FitzKRC@aol.com
Ashley@kyrc.org

Counsel for Joint Intervenors
Metropolitan Housing Coalition,
Kentuckians for the Commonwealth,
Kentucky Solar Energy Society and
Mountain Association

CERTIFICATE OF SERVICE

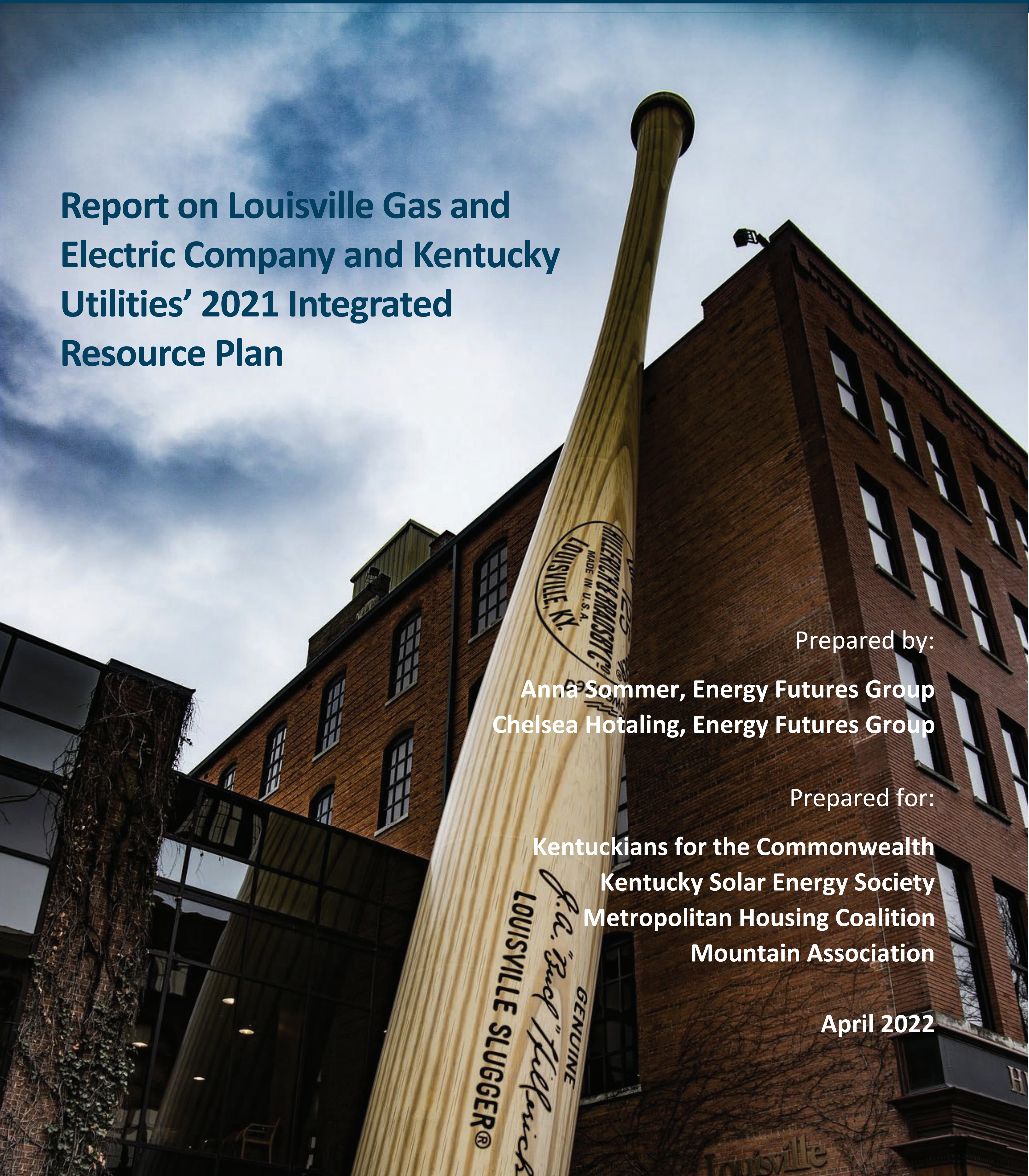
In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, Electronic Emergency Docket Related to the Novel Coronavirus COVID-19, this is to certify that the electronic filing was submitted to the Commission on April 22, 2022; that the documents in this electronic filing are a true representations of the materials prepared for the filing; that no hard copy of this filing will be made; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

____
Tom FitzGerald

Exhibit 1

ENERGY FUTURES GROUP

energyfuturesgroup.com



Report on Louisville Gas and Electric Company and Kentucky Utilities' 2021 Integrated Resource Plan

Prepared by:

Anna Sommer, Energy Futures Group
Chelsea Hotaling, Energy Futures Group

Prepared for:

Kentuckians for the Commonwealth
Kentucky Solar Energy Society
Metropolitan Housing Coalition
Mountain Association

April 2022

Table of Contents

Table of Figures

Table of Tables

1 Summary and Introduction

1.1 Introduction

Energy Futures Group ("EFG") was asked by Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Kentuckians for the Commonwealth, Metropolitan Housing Coalition, and Mountain Association ("Joint Intervenors") to perform a review of Louisville Gas & Electric's and Kentucky Utilities' (the "Companies") 2021 Integrated Resource Plan. The review was performed by Anna Sommer, Principal and Chelsea Hotaling, Consultant from EFG. EFG is a clean energy consulting company that performs IRP modeling and critically reviews IRPs in over a dozen states, provinces, and territories. We've reviewed over 100 integrated resource plans and similar exercises in our over 25 years of combined experience.[1] 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 the three used by the Companies: PLEXOS, PROSYM, and SERVM.

Our recommendations throughout this report are intended to provide feedback on how the Companies can transition to an IRP approach that is typical or even best in class relative to its peer utilities.

1.2 Summary

In the words of Lawrence Berkeley National Laboratory ("LBNL"), "[r]esource planning processes provide a forum for regulators, electric utilities, and electricity industry stakeholders to evaluate the economic, environmental, and social benefits and costs of different investment options. By facilitating a discussion on future goals, challenges and strategies, resource planning processes often play an important role in shaping utility business decisions."[2] Effective and meaningful IRPs do not merely serve as checklists for a set of analyses; rather, they reflect thorough and thoughtful stakeholder engagement, set forth the utility's perspective and analytical processes, clearly communicate the analyses that combine to make the IRP, are well documented and give a clear decision making path for the utility. In addition, well-done IRPs often discuss the ways in which the utility's next IRP might change in the future, such as how assumptions may change or further analyses the utility might conduct in preparation for its next IRP.

While the Companies have been very willing to answer discovery and respond to questions in the two one-on-one discussions we had with their technical staff, the Companies' IRP filing lacks a number of important components that are typical, if not best practice. For example, we saw no indication of stakeholder engagement in the preparation of the IRP, the core analyses of the IRP were appended together with little explanation about how they relate, the Companies said very little about the considerations that went into selecting its preferred resource plan, and the documentation that we received in discovery often lacked key details and/or was not properly documented so as to be understandable by an external party. The IRP does not articulate which is the Companies' preferred

[1] The resumes of Ms. Sommer and Ms. Hotaling are attached to these comments as Attachments A and B.
[2] Karhl, Fritz, et. al. "The Future of Electricity Resource Planning". Lawrence Berkeley National Laboratory. September 2016. Available at: https://emp.lbl.gov/sites/all/files/lbnl-1006269.pdf

resource plan. Finally, the Companies gave no indication in the IRP about how its approach to integrated resource planning might change in its next IRP.

Our review also revealed some serious concerns with the validity and robustness of the Companies' modeling approaches. The Companies' IRP does not contain a fulsome analysis of all the resource options available to it, does not comport with best in class or even typical IRP modeling techniques, and does not help the Commission to judge whether its plan really is the "lowest reasonable cost". There is a better path available to the Companies and the Commission and the following section articulates an example of such a pathway.

1.3 A Different Approach to Integrated Resource Planning

In the mid-2010s, South Carolina Gas & Electric ("SCG&E") was involved in an effort to build its first nuclear power plant in over thirty years. With costs ballooning to $25 billion and the project years behind schedule, the utility abandoned the project in mid-2017.[3] Because of this and the subsequent litigation associated with the project, in 2019, South Carolina's IRP process was revamped to become substantially more thorough and comprehensive. As a result, in its order on the first IRP from SCG&E's predecessor company, Dominion Energy South Carolina ("DESC"), the South Carolina PSC required DESC to:

1. More thoroughly and broadly model demand-side, solar, and battery storage resources,
2. Use a broader set of metrics to judge which plan to select,
3. Establish a stakeholder process to invite stakeholder review and input of DESC's "methodology, inputs, and assumptions",
4. Perform a comprehensive coal plant retirement analysis,
5. Make available without need for a data request "the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual", and
6. Negotiate "a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package as DESC, and to direct DESC to absorb the cost of these licensing fees."

In the approximately 18 months since the Commission's order, DESC has made the following improvements:

1. Moved from PROSYM, an outdated and unsupported model incapable of doing such things as modeling paired solar and battery resources, to PLEXOS. PLEXOS, though it has its limitations, is a well supported and well documented model that is capable of sophisticated electric and transmission planning analysis.
2. Began a stakeholder process that has covered such important topics as how to model energy efficiency and demand response resources, how to study the transmission impacts of coal plant

[3] Larson, Aaron. "Former SCANA CEO will Land in Prison as Result of V.C. Summer Nuclear Project." PowerMag. October 15, 2021. Available at: https://www.powermag.com/former-scana-ceo-will-land-in-prison-as-result-of-v-c-summer-nuclear-project/

retirements, how to measure reliability, how to characterize the cost and performance of new resources, and many other topics.

3. Filed a modified IRP that was so much more thorough, well written, well supported, and better documented that rather than almost universally asking the Commission to reject its IRP as they did for its prior filing, stakeholders universally asked the Commission to approve it.

DESC is not uniquely capable of this transformation and it's important to be clear that this transformation is ongoing. 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. And the South Carolina Commission's direction was critical to starting DESC down the path of this transformation.

Certainly, the circumstances of the Companies' efforts to build new generation are different and the rules that apply in Kentucky are different, but there are enough commonalities that we think this example is very applicable. Kentucky's IRP rules cover a broad set of analyses and data points. For example, the IRP rules invite the Companies to describe all options considered in its plan:[4]

> *(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;*
> *(b) Conservation and load management or other demand-side programs not already in place;*
> *(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and*
> *(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.*

Instead, the Companies appear not to have explicitly evaluated the economics of any additional DSM programs nor any additional nonutility generation. Without interpreting the legal meaning of such language nor opining about the Commission's intent in promulgating this language, we would expect that specifics such as these are given because they are of importance to the Commission and the state of Kentucky and because such assessments are the typical work of IRPs.

This is just one reason that we see Kentucky's IRP rules as providing a good framework for a much more comprehensive, well-documented, and meaningful IRP.

1.4 Recommendations

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

[4] Section 8(2)

1. Encourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs and assumptions including, but not limited to:
    a. The Companies' reserve margin study;
    b. The development and modeling of the portfolios considered in the IRP;
    c. The manner in which unit retirement is evaluated;
    d. The RTO membership analysis;
    e. The source of and manner in which new resource costs and supply are developed, e.g. demand-side management and other distributed energy resources; and
    f. The modeling tools used in the development of the IRP.
2. Encourage the Companies to negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package(s) and encourage the Companies to absorb the cost of these licensing fees.
3. Clarify that upon filing of an IRP, LG&E/KU should make available, on request and ideally simultaneously with filing of the IRP, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual(s).
4. Recommend that the Companies adopt the typical practice of using a single model for capacity expansion and production cost modeling.
5. Direct the Companies to model a full planning period and not just a single year.
6. Encourage the Companies to document their analytical work so that it clearly conveys the steps taken and information relied upon.
7. Encourage the Companies to limit out-of-model adjustments and include as many system costs in the model as is feasible.
8. Direct the Companies to economically evaluate all potentially cost-effective resource options available to it, specifically including a wide range of levels of new and expanded Demand-Side Management ("DSM") and other distributed energy resources ("DERs") such as distributed solar and storage. The DSM levels should be developed through the meaningful and participatory collaboration of the DSM Advisory Group as previously recommended by staff.
9. Direct the Companies to consider key issues or uncertainties potentially impacting their resource plan, particularly including analysis of the impacts of a CO_2 price and meeting a significant emission reduction goal such as PPL's corporate goal on the Companies' resource plans.
10. Encourage the Companies to cease use of the Equivalent Load Duration Curve Model ("ELDCM") for reliability modeling.

Our recommendations are intended to provide feedback on how the Companies can transition to an IRP approach that is typical or even best in class relative to its peer utilities.

2 Modeling Methodology

2.1 Companies' Modeling Approach

The Companies used a nontraditional modeling approach to create this IRP. First, the Companies performed two "reserve margin analys[es]" from which the Companies determined the planning reserve margin ("PRM") used in its subsequent modeling steps. The PRM specifies the amount of capacity in excess of the Companies' peak load that is needed to meet the Companies' reliability standard. A PRM is a common proxy for reliability used in IRP modeling, but there is a more direct and accurate way to measure reliability, which we discuss in Section 4.2. The reserve margin analyses were also used to determine whether to retire any of the Companies' existing thermal units. This is a highly unusual approach and suffered from a number of issues that we discuss in Section 4.

The Companies then moved to their next step using PLEXOS. This step, called capacity expansion modeling, created portfolios of resources that would meet projected 2035 load. Capacity expansion modeling involves utilizing an optimization engine to minimize system costs given the costs of new and existing resources including a simplified[5] projection of unit commitment and dispatch.[6] One of the inputs into the capacity expansion model is the PRM. When the model is choosing the least cost portfolio, it will seek to minimize the cost of a plan that meets peak load plus the PRM. The Companies' approach in this step was unlike any IRP we've examined previously in that only the year 2035 was modeled. Normally, a capacity expansion simulation will look at each year of the planning period, in this case 2021 – 2036. Annual time steps are the norm because they provide information about the timing related value of the model's choices, e.g. whether it makes more sense to retire a coal plant in 2025 or 2035 or whether to start expanding energy efficiency programs now or wait a few years. This important information is lost under the Companies' methodology because only one year of the planning period is simulated. The choice of when to take the actions the model identifies as optimal are then entirely up to the Company's discretion.

The Companies then moved to their next step, production cost modeling using a third optimization software called PROSYM. A portfolio must be fixed for this modeling, the model does not optimize the resources within each plan. Instead, the purpose is to simulate the operation of the portfolio on an 8,760 hour per year, chronological basis in each year of the planning period. The results from the production cost modeling are then combined with the capital and other fixed costs in the capacity expansion modeling to develop the total costs of the portfolios evaluated. Here too, the Companies took an approach we have never seen. Rather than using PLEXOS for production costing, it moved one of its plans over to PROSYM and simulated a single plan. This is highly unusual for several reasons, one being that the primary use case for PLEXOS is production cost modeling. PLEXOS is a very powerful, customizable tool for this purpose. There are dozens of utilities who license PLEXOS for dispatch

[5] In order for the model to reach a solution the "problem size" has to be manageable, a common way to limit problem size is to simulate only a handful of hours, such as two "typical" days per month in the capacity expansion step.

[6] The model can also optimize for any external market interactions.

simulation reasons such as power marketing, fuel budgeting, maintenance scheduling, etc. In contrast, PROSYM is no longer supported by its vendor and lacks many of the capabilities of contemporary modeling tools such as the ability to properly optimize battery storage, the ability to pair solar with battery storage, etc. See page 2 of Attachment C, which was prepared by Duke Energy for additional information and concerns about PROSYM.

The Companies then combined different pieces of these analyses, made certain out-of-model adjustments to costs, and then created a set of revenue requirements. Those steps are shown in Figure 1, below. The out -of- model adjustments included accounting for fly ash and gypsum sales revenue, the capital and fixed O&M costs for new generation, and the Companies' calculation of the fixed O&M and capital maintenance[7] for existing resources.

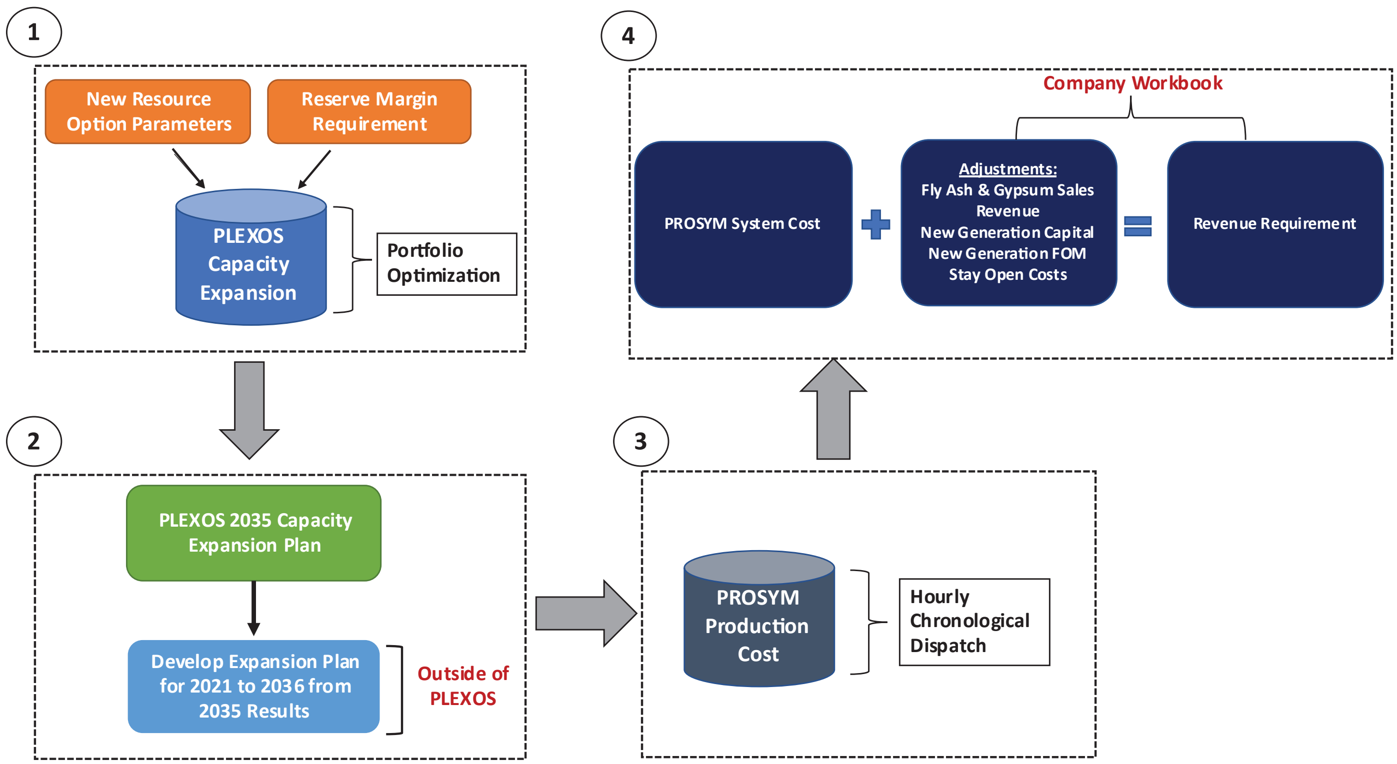


Figure 1. The Companies' Modeling Process

2.2 Recommended Modeling Approach

We have serious concerns about the Companies' modeling approach for this IRP. Figure 2 depicts the modeling process that we usually see utilized by utilities using PLEXOS for IRP modeling.

[7] The Companies refer to these as "Stay Open Costs".

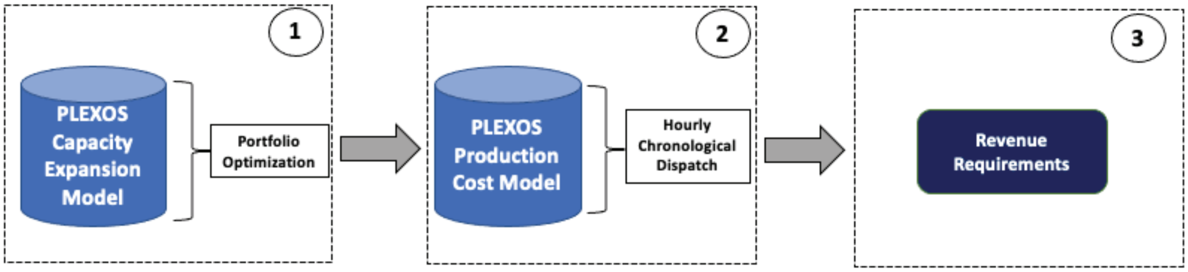


Figure 2. Capacity Expansion and Production Cost Modeling Process

It is more traditional for utilities to leverage the same software for the capacity expansion and production cost modeling steps and not break these two steps out into two different models. For example, the three primary electric system models we see used in IRPs, EnCompass, Aurora, and PLEXOS, all have the capability to perform capacity expansion and production cost modeling. There are a variety of reasons for the use of one model, the first being that it's more cost-efficient to do so, as only one license fee has to be paid. Another is that it reduces the opportunity for errors. While these models typically require similar types of information, they have different formatting requirements, so there is room for additional errors in translating the data from one model into the format required for another model. A third reason is that using one model saves time. It's much easier to launch a production costing run immediately after the capacity expansion run if the same model is used. In fact, at least one of these models can be scripted to do that automatically. Finally, there isn't such a huge differential in tool capabilities that it would make sense in most circumstances to use one of these tools for capacity expansion modeling and another for production cost modeling. There may be reasons to use two modeling tools when there are additional purposes in mind, e.g., a resource adequacy or reserve margin study, because tool capabilities become a more salient point. So the use of SERVM for that purpose makes sense. But for IRP modeling purposes, it's hard to envision a reason to use more than one tool.

We have also never seen a utility utilize a capacity expansion model to only perform portfolio optimization for a single year of the planning period. It is our recommendation that the development of expansion plans should include the entire planning period that is being modeled for the IRP so that the model can make optimal decisions about which year resources should be added and/or retired.

Once the utilities perform portfolio optimization within the capacity expansion model, that capacity expansion plan will then be passed onto the production cost side of the model to perform the hourly chronological dispatch of the utility's system. Typically, the model combines the results of the production costing step with the capital results from the capacity expansion step to develop the revenue requirements. The revenue requirements are then used to compare competing, feasible plans. Out-of-model adjustments are normally limited to costs that are difficult to model, e.g., not fixed O&M, but externality costs of emissions, etc. Reducing these adjustments as much as possible makes the modeling process more efficient, allows these factors to influence the portfolio optimization, and also reduces the opportunity for error.

3 Modeling Methodology Concerns

Table 1 below highlights the concerns we have identified with the Companies' modeling approach along with our recommendations for how the Companies can move to an IRP modeling approach that is consistent with practices of its peer utilities. The following sections go into more detail about our concerns with the Companies' modeling and our recommendations.

Table 1. Concerns with Companies' Modeling Approach

Concern	Recommended Approach
1. Companies' IRP did not include a stakeholder process for reviewing modeling inputs and assumptions	Conduct stakeholder workshops that allow interested parties to provide feedback to the Companies on modeling inputs and assumptions
2. Companies performed capacity expansion optimization only for the year 2035	Perform capacity expansion optimization for each year of the entire planning period
3. Companies used two different models to perform capacity expansion and production cost modeling	Utilize one model for capacity expansion and production cost modeling
4. Companies only ran production cost modeling for the Base Load and Base Fuel Case and no sensitivities	Perform production cost modeling for all modeling runs developed for the IRP
5. Companies did not evaluate differing levels of DSM or other DERs to be considered as a resource option in the capacity expansion optimization	Develop assumptions for differing levels of DERs and evaluate the cost and portfolio implications of those choices
6. Companies did not evaluate a CO_2 price or the impact of significant CO_2 emissions reduction in this IRP	At the minimum, model portfolios consistent with PPL's corporate carbon reduction goals
7. Companies did not appear to model interchange with surrounding utilities/balancing authorities in the capacity expansion and production cost modeling.	The Companies ought to include interchange with external entities because that's reflective of the Companies' normal operations.

3.1 Lack of Stakeholder Process

The Companies did not include a stakeholder process leading up to the filing of the IRP. As the Companies indicated in a discovery response to the Southern Renewable Energy Association ("SREA"), the Companies believe that a stakeholder process is not a requirement of the IRP rules:

> *The Companies did not have a 2021 IRP stakeholder engagement process and have not had such a pre-filing process for any previous IRP. Unlike demand side management plan filings for which there is a statutory requirement to consider the involvement of "customer representatives and the Office of the Attorney … in developing the plan," the*

> *Commission's IRP regulation neither requires nor contemplates a pre-filing stakeholder process. Rather, the IRP regulation provides a process by which the Commission Staff and intervenors may issue discovery requests and submit comments about an IRP after a utility files it. Likewise, the Commission may schedule conferences to discuss an IRP after a utility files it. But the regulation does not require or even suggest a pre-filing public or stakeholder process.* [8]

While we understand that the IRP regulation may not require the Companies to hold meetings with stakeholders prior to the filing of the IRP, it also does not preclude it. And it is our experience in other jurisdictions that a stakeholder process leading up to the filing of the IRP results in a more robust outcome for the IRP. Indeed, such a process is typical of the IRPs in which we are involved. During these workshops, utilities share information with stakeholders on modeling inputs and assumptions and those parties have the opportunity to engage with the utility and provide feedback. In our experience this process allows the utility to adjust its IRP to accommodate stakeholder concerns, better understand the perspectives of stakeholders, and allows stakeholders to understand the Companies' thought process and concerns. This can help narrow the issues the staff must consider as well as improve the ability of the IRP to address stakeholder concerns. It's our experience that only involving stakeholders after the IRP is filed results in little meaningful engagement and tends to delay improvements that would otherwise be made in subsequent IRPs.

3.2 Capacity Expansion Modeling

3.2.1 Planning Period Modeled

As discussed in Section 2, the Companies used an atypical approach to capacity expansion modeling for this IRP where only one year of the planning period was modeled for capacity expansion planning. The Companies utilized PLEXOS for the capacity expansion modeling step. PLEXOS is capable of performing capacity expansion across much longer planning horizons so we are surprised to see the Companies chose to simulate only the year 2035[9] and it's unclear why they did so.

Since the Companies only optimized for the year 2035, this means that the Companies had to perform an additional step outside of PLEXOS to spread the resources included in the 2035 capacity expansion plan across the IRP planning period that covers 2021 to 2036.

It is our understanding that the Companies are still in the process of understanding PLEXOS' functionalities, but we are concerned that they will use this same methodology of solving for only one year in the planning period in future IRPs or CPCN filings. As the Companies said in a discovery response to the Joint Intervenors:

> *The Companies intend to use PLEXOS for expansion planning in future IRP and CPCN filings. The Companies have not developed plans for any future filings, but time periods for IRP filings will*

---

[8] Case No. 2021-00393. Companies' Discovery Response to SREA's Question 1.4a.
[9] Case No. 2021-00393. Companies' Discovery Response to Joint Intervenors' Question 2.19.

likely consider part or all of the 15-year IRP planning horizon and CPCN filings will likely consider part or all of a 30-year planning horizon.[10]

We strongly recommend that the Companies model the entirety, and not just part, of planning horizons for both IRP and CPCN filings.

3.2.2 Lack of Energy Efficiency, Demand Response, and other DERs

For this IRP, the Companies did not model new DSM programs despite saying in the IRP narrative that "The Companies' DSM-EE programs have been a tremendous success".[11]

> *The Companies did not directly evaluate new DSM programs for this IRP because not doing so was consistent with the Commission's IRP regulation, over 20 years of IRPs filed by the Companies, and the Commission Staff's report on the Companies' 2018 IRP. But that is not to say that the Companies are not actively evaluating current and future DSM and energy-efficiency programs; rather, the Companies are doing just that, which is consistent with the Commission's orders in the Companies' 2020 rate cases. The Companies' analysis and DSM Advisory Group process will use the outputs of the 2021 IRP as inputs to the Companies' next DSM-EE Program Plan.*
>
> *With regard to why the Companies did not directly evaluate new DSM programs for this IRP, the Commission's IRP regulation requires utilities to "describe and discuss all options considered for inclusion in the plan including … [c]onservation and load management or other demand-side programs not already in place," but it does not direct utilities to conduct an IRP-specific study or analysis of new DSM-EE programs per se. Indeed, the Companies have never conducted such a study or analysis for a previous IRP, and the Commission has not directed them to do so. Notably, the Commission Staff's report on the Companies' 2018 IRP did not recommend that the Companies include in their next IRP an analysis of DSM-EE programs the Companies did not have, but rather stated, "The Companies should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders." The report further states that "Staff encourages LG&E/KU to continue exploring cost effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time." The Companies have done and are doing precisely those things, which do not involve directly evaluating new DSM programs in an IRP.*
>
> *Although the Companies do not specifically analyze new or currently unused DSM-EE programs for their IRPs, their IRPs do provide valuable inputs to the analyses that support the Companies' DSM-EE program plan filings. In this IRP, the Companies show they do not have a capacity need until 2028. Also, this IRP identifies the types of resources the Companies could potentially eliminate or defer through future DSM-EE programs. For example, the resource expansion plan for the base load, base fuel price case in this IRP includes new simple-cycle combustion turbines*

[10] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors' Question 2.1e.
[11] Louisville Gas and Electric Company and Kentucky Utilities Company IRP, page 8-19.

> *and battery storage for integrating renewables and serving peak load, particularly in the winter. As discussed on page 23 of the Companies' Long-Term Resource Planning Analysis (Volume III), successful deployment of new DSM-EE programs could reduce or defer the need for these resources. The timing of the Companies' need for capacity and the costs of the likely supply-side resources this IRP identifies are direct and necessary inputs to the Companies' cost-benefit analyses of future DSM-EE program plans.*
>
> *With information from this IRP and data associated with the implementation of AMI, the Companies plan to evaluate new DSM programs as an alternative to new generation resources for meeting their 2028 capacity need. A proactive and thorough DSM program review is underway, which has included multiple collaboration meetings with the DSM Advisory Group, as well as a recently completed Demand Response Potential Study. Also, the Companies will be submitting a filing in the first half of 2022 to request an increase to the budget for the Non-Residential Rebate Program due to higher than expected program participation.*
>
> *Therefore, the Companies' 2021 IRP is fully consistent with the Commission's IRP regulation, prior practice, and Commission Staff recommendations regarding DSM-EE programs the Companies are not currently deploying. Moreover, the Companies are actively analyzing and working to pursue additional funding for current DSM-EE programs, as well as future DSM-EE Program Plan Filing.*[12]

Our recommendation is to move the Companies to an approach that directly evaluates additional DSM programs, as this is in fact supported by Kentucky's IRP rules, by the Staff's encouragement to "LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time", and by the existence of a DSM Advisory Group. Moreover, considering additional DSM in IRP's is typical practice amongst peer utilities; this is on top of the importance of these programs to resiliency, customer affordability, and reliability.

It is not just typical practice, but good practice, to evaluate the economics of additional DSM programs in IRPs. The IRP should consider a wide range of potential savings and costs in comparison to supply-side investments and retirements. The Companies give a multitude of rationales for not doing so including "the Companies show they do not have a capacity need until 2028", but it will take time to build up DSM savings such that they can defer or help defer new capacity. The lack of capacity need until 2028 is entirely a product of the Companies' discretion. Because the timing of resource additions and retirements was developed without benefit of any optimization, a capacity need in 2028 or any other specific date was not explicitly determined in this IRP.

The Companies also say, "With information from this IRP and data associated with the implementation of AMI, the Companies plan to evaluate new DSM programs as an alternative to new generation resources for meeting their 2028 capacity need." Many utilities have been implementing broad reaching

[12] Case No. 2021-00393. Companies Discovery Response to Commission Staff's Question 1.4a.

and successful EE programs for a decade or more without the use of AMI data. Furthermore, the Companies haven't articulated the when, how, or what of this evaluation of new DSM programs. What programs would be considered? When and how will they be evaluated and if cost-effective, what happens next? This lack of consideration of additional DSM in this IRP is a critical flaw and contrary to the IRP rules which require the Companies' to "describe and discuss all options considered for inclusion in the plan including:…(b) Conservation and load management or other demand-side programs not already in place".[13]

While not as frequently the subject of economic evaluation in IRPs as DSM, distributed solar may have the ability to play an important role on the Companies' system and ought to have been evaluated here. As shown in Figure 5-13 of the IRP, replicated here as Figure 3, the Companies foresee the potential for significant buildout of distributed solar. In the IRP, the Companies state that "in the high scenario, a new federal law is assumed to eliminate the 1% cap on total installed net metering capacity." However, it's important to recognize that the 1% threshold is not, in fact, a cap that limits the utilities' ability to offer net metering. The relevant Kentucky statute says, "If the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year, the supplier **shall have no further obligation** to offer net metering to any new customer-generator at any subsequent time [emphasis added]."[14] In other words, utilities have the option to continue offering net metering beyond the 1% threshold. The Companies can and should consider the value of offering additional net metering through the IRP. There are a number of tools available that would allow the Companies to create supply curves of distributed solar and their associated incentive costs. That curve can be offered to the IRP model as one of many resources to select.

[13] 807 KAR 5:058, Sec. 8(2).
[14] KRS 278.466.

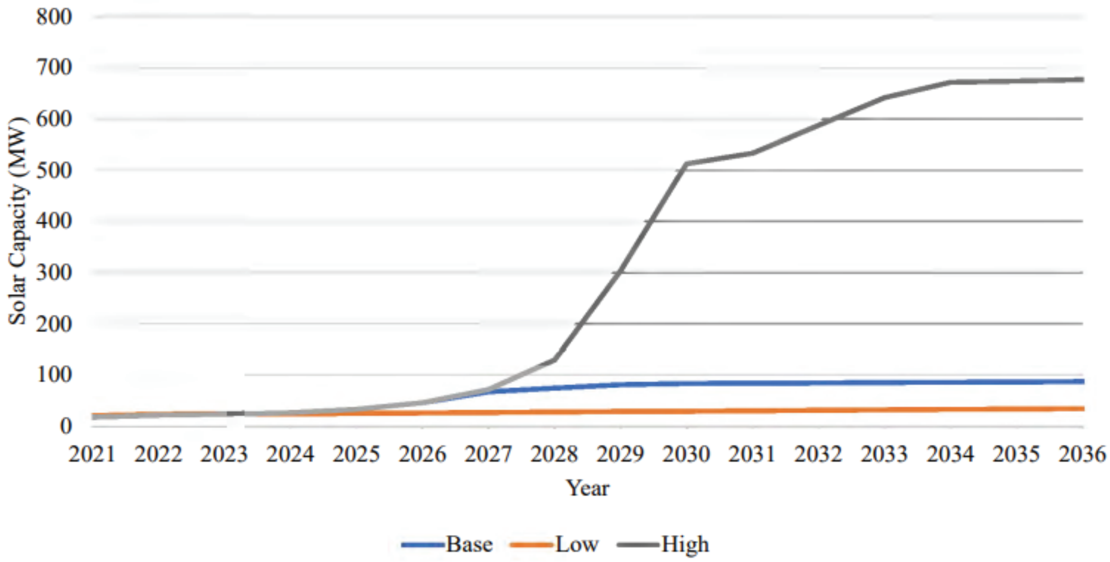


Figure 3. Distributed Generation Forecast Scenarios

The supply curve can also be tailored as dictated by the circumstances of the Companies' system. For example, net metering is a key measure to ensure affordability for low-income customers, so the revenue requirements impacts of a program open exclusively to this group could be evaluated.

Distributed solar may also offer complementary benefits to the utilities' system in the form of increased bulk level reliability. Indeed, Figure 5-15 of Volume I of the IRP suggests that the "high" level of distributed solar could provide several hundred megawatts of summer peak shaving capability.

3.2.3 Lack of Evaluation of Economic Plant Retirement

We normally see utilities consider the economics of retiring existing thermal plants in their IRP modeling either by allowing the capacity expansion model to optimize a retirement date or modeling portfolios that consider different early retirement dates for plants. The Companies' considered generator retirements in their reliability modeling through an approach we would strongly encourage be abandoned (Section 4). In order for a more typical approach to be used in subsequent IRPs and CPCNs, the Companies will need to model a full planning period rather than a single year.

3.2.4 Lack of Documentation of PLEXOS Modeling

IRP modeling is certainly complex, but our position is that it should be fully reviewable and even replicable with access to the same software package. We encountered significant issues in reviewing the Companies' modeling. The IRP and the PLEXOS files that were provided by the Companies through discovery lack information about how the Companies conducted capacity expansion modeling within PLEXOS. While we know that the Companies only performed capacity expansion optimization for the year 2035, it is still unclear whether tunnel constraints[15] were placed on the new resources that could be selected in the optimization. In response to the Joint Intervenors' discovery question asking if the

[15] Tunnel constraints are typically either annual or cumulative limits on new resources that the model can select. Examples of tunnel constraints include only allowing 250 MW of solar resources to be selected in a given year of the capacity expansion modeling or setting a constraint that a new CCGT can only be selected in 2028.

Companies placed limitations on the amount of solar, wind, and battery resources that could be selected in each year or cumulatively, the Company responded simply "No".[16] We couldn't verify that response ourselves because the appropriate PLEXOS input file was not provided, but we found this response confusing because normally a limit of some kind, even if it is an inordinately large number such as fifty 100-MW wind projects each year, is used so that the model can solve.

The Companies have also admitted that they made changes to the model data within the interface, so some of the modeling files we received are inaccurate because they don't also contain those changes. For example, after reviewing the PLEXOS modeling input files that were provided through discovery, we had some questions regarding inputs that seemed to be specified for some generators, but not for battery storage. We asked in discovery that the Companies explain where the firm capacity assumptions inputs for battery storage resources could be found because the input file we were provided with only had this information for the thermal generators. In response to this question, the Companies said, "The firm capacities of batteries are entered directly via PLEXOS's user interface." [17]

Furthermore, the new modeling runs performed in response to Staff's request for runs that include a CO_2 price were documented only in narrative form. The results added to our confusion about what resources were considered in PLEXOS and whether any constraints were applied to new resource choices. The original PLEXOS input files we received show new NGCC resources with and without carbon capture and sequestration ("CCS") and no constraint preventing the model from choosing either resource. This despite the fact that the Companies said NGCCs without CCS were not considered, "Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions."[18] This new modeling prepared at Staff's request shows both NGCCs with and without CCS being added, which means that some constraint, which we could not see in the modeling, had to have been relaxed. This is just one way in which the modelers' choice of settings and parameters can heavily influence the model results and a reason that we feel so strongly that model inputs and outputs should be fully reviewable.

3.3 Production Cost Modeling

3.3.1 Use of a Different Model from Capacity Expansion Model

One of the other nontraditional modeling approaches the Companies used for this IRP is the use of different models for capacity expansion and production cost modeling, as we described in Section 2.1. Over the past four years, there has been a major shift in the IRP modeling tools used by utilities. In the past, the vast majority of utilities comparable to the Companies used ABB's Strategist, Capacity Expansion, and/or PROSYM platforms for IRP purposes. However, when ABB ceased supporting these tools, many utilities moved to EnCompass, PLEXOS, or Aurora. All three of these models can perform both capacity expansion and production cost modeling. When we asked the Companies why they did

[16] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 1.29d.
[17] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.21.
[18] Louisville Gas and Electric Company and Kentucky Utilities Company IRP, Vol. I, page 5-39 to 5-40.

not utilize PLEXOS for production cost modeling, the Companies response was that "PLEXOS was acquired primarily to support the Companies' expansion planning efforts, so work to date has prioritized utilization of PLEXOS as an expansion planning tool".[19] It is our recommendation that the Companies should discontinue the practice of using two different models for capacity expansion and production cost modeling, and use the same model to perform these steps for the IRP.[20] Doing so would make the Companies' analysis more robust and accurate, streamline the review of its modeling, and allow for a more complete picture of the performance of all the portfolios it is evaluating.

We would encourage the Companies to carefully consider its IRP model options. We've seen other utilities successfully use a combination of temporarily licensing models of interest as well as soliciting the feedback of stakeholders to choose a new model. The criteria that DTE Energy used for exactly this process may also be helpful to the Companies and are attached to these comments as Attachment D.

3.3.2 Concerns about Production Cost Modeling of only the Base Fuel and Base Load Case

The Companies developed several scenarios that comprised different combinations of low, base, and high forecasts for load and fuel prices. Each scenario results in a corresponding expansion plan, rather than differing expansion plans being subjected to multiple scenarios. Since differing combinations of load and fuel forecasts were used, each scenario has its own expansion plan specific to that scenario combination. Despite the fact that the Companies developed multiple scenarios, the Companies did not actually perform production cost modeling for all these scenarios/plans. The only run that was simulated in PROSYM was the Base Load and Base Fuel scenario.[21] And because each scenario was not run through the production cost model, the Companies were unable to develop present value of revenue requirements ("PVRRs") for each scenario. This means that the Companies cannot compare the cost of the scenario-specific portfolios against each other. Nor would the Companies be able to understand how different plans perform under different scenario assumptions.

3.3.3 SCCT Capacity Factor Limits

The Companies said in discovery that "New simple cycle combustion turbines were limited to a maximum capacity factor of 20%."[22] It does not appear that this capacity factor limit was applied to the new SCCTs modeled in PROSYM as there are instances in the run where the SCCTs operate at a capacity factor above 20% between 2028 and 2036. We are not sure if the intention was to apply the constraint in PLEXOS, but not in PROSYM, or if this is another product of the difficulty in using two different models and the constraint was simply left out in the process of developing different sets of inputs.

3.4 Multi-Model and Multi-Step Methodologies are Prone to Error

3.4.1 The Companies' Approach Relies on Multiple Tools and Workbooks

The Companies used an unusually large number of modeling tools, four if the ELDCM spreadsheet tool is included, and many workbooks to characterize both inputs and outputs. In several instances, we found it

[19] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors' Question 2.1b.
[20] Note that PROSYM is not capable of doing both these steps.
[21] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors' Question 2.33a.
[22] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 1.54e.

difficult to understand the purpose and approach of the analysis in the Companies' Excel workbooks. Some workbooks seemed to contain information from a prior IRP that was not being used for this IRP, a fact we only learned through discovery seeking clarification of the data we were looking at. Many workbooks contained information that was hardcoded and undocumented, so it was not clear where the information was coming from or how it had been used. No person or entity is immune to mistakes and the more involved a modeling process is the more room for error there is. This is just one reason to narrow the use of modeling tools and to allow the tools themselves to do as many of the financial and other calculations and data querying as possible.

We also believe reducing the number of steps and tools would allow the Companies to perform more meaningful analysis. Only one plan/scenario was simulated in the Companies' production costing tool, PROSYM, and that was also the only plan/scenario for which costs were reported in the IRP. **There's no meaningful point of cost comparison given for the plans evaluated by the Companies and no way for the Companies to demonstrate that any plan is "lowest reasonable cost".**

The Companies have said that one reason they prefer PROSYM is because they've created tools supporting the PROSYM inputs and outputs including:[23]

> *numerous spreadsheets, along with custom reporting queries developed in an Access database called Reporter, and the ability to create and read cases in bulk with a SAS program called Case Developer.*

First of all, the Companies did not evaluate multiple cases in PROSYM for this IRP, they evaluated one case. And at least some of these capabilities are built into models such as EnCompass, Aurora, and PLEXOS which reduce the need to use multiple software programs and steps outside the model. For example, EnCompass reads and exports data entirely in Excel, so calculations used to develop input assumptions and their documentation can be embedded into EnCompass' input files and post-processing of outputs can be directly linked to the output files. To give another example, one can create "change sets" in Aurora that will modify the underlying database and can be universally or selectively applied to the study cases. Those study cases can then be run individually or in batch mode. We understand that it takes a long time to become familiar with a model and fully utilize its capabilities, but institutional familiarity with a model is not a good reason to stick with a model over one that is more powerful, better supported, more transparent, more accurate and may even be cheaper.

3.4.2 Inability to Reconcile the Production Cost Files with the Companies' Revenue Requirements Calculations

In Supplemental Discovery, the Joint Intervenors asked the Companies clarifying questions related to the PROSYM production cost outputs and the manner in which those were integrated into the Companies' revenue requirement workbook. The Companies said that, "The production cost components of revenue

[23] Case No. 2021-00393, Companies 'Discovery Response to Joint Intervenors Question 2.1a.

requirements for this portfolio are available at a system level in the "out_stationyr.csv" file as "SysCost" in column D."[24] After reviewing the system costs reported in the "out_stationyr" output file from PROSYM, we were unable to verify that the costs reported in this file were the costs used in the development of the revenue requirement calculation[25] as we could not match the costs from the PROSYM output file with the Companies' workbook creating the revenue requirements.

The process that the Companies used to combine the PROSYM system costs with the FOM for existing resources and capital costs for new resources to develop the annual revenue requirements spanned multiple workbooks, often involved hardcoded numbers, was confusing to review, and was not well documented and means that the Commission, Staff, and stakeholders cannot replicate the Companies' revenue requirements calculation.

3.4.3 Treatment of the Investment Tax Credit

The Companies developed a levelized $/MW-year charge for new resources considered in PLEXOS, but used a post-processing adjustment to include the capital costs for new resources in the PVRR of the Base Load and Base Fuel case. For reasons that are unclear, whether it be error or intention, the costs of solar modeled in PLEXOS reflected the investment tax credit, but the costs included in the PVRR did not. The Companies acknowledged this discrepancy in the Companies' response to Joint Intervenors question 2.35 and the Companies provided an updated PVRR. While we recognize that this did not significantly impact the PVRR results, this discrepancy is an example of what can happen when multiple steps and models are used to develop an IRP.

3.5 Carbon Price and/or Carbon Reduction Goal

Initially, the Companies did not consider the impact of a CO_2 price. In discovery, the Companies said, "the most reasonable CO_2 price for the Companies is currently $0."[26] This is very different from the approach we typically see utilities use - a CO_2 price and/or a carbon reduction constraint are normally modeled. Some utilities include a CO_2 price in their base case modeling assumptions and then consider other sensitivities with a wider range of prices. Some utilities create two base cases, one without a CO_2 price and one with such a price. Some model both a price and a target level of reduction, e.g. 85% by 2040.

The Companies' subsequent modeling in response[27] to Staff's request used $15 and $25 per ton CO_2 prices. The Companies did not provide the modeling input and output files that were used for these additional modeling runs, but we are skeptical of the conclusion that CCGTs are the least cost way to avoid carbon emissions as the Companies' modeling for Staff claims to show. The retirement choices made in each run would encourage the model to add capacity resources and it's not clear what resources the model could choose from. The Companies suggest that gas combined cycle units are least cost, even in comparison to solar, at $23 per MWh because that figure accounts only for fuel or fuel plus

---

[24] Case No. 2021-00393, Companies Discovery Response to Joint Intervenors Question 2.33c.
[25] Workbook named "CONFIDENTIAL_20210928_LAK_Section8Tables_2021IRPD02".
[26] Case No. 2021-00393, Companies' Discovery Response to Commission Staff's Question 1.9.
[27] Case No. 2021-00393, Companies' Discovery Response to Staff's Question 2.1b.

variable O&M, not capital. This raises questions about whether the capital costs of NGCCs were also considered in PLEXOS. In addition, PLEXOS is only optimizing this portfolio for a carbon price faced in a single year to determine the so-called least cost plan of assets with multiple decades of life. As with many other concerning aspects of the Companies' IRP, these problems can be fixed by simulating a full planning period (running the capacity expansion model for each year of the study period), allowing the IRP model to do as many resource optimization decisions and financial calculations as possible, and making the modeling fully reviewable by stakeholders.

3.6 Additional Best Practice Recommendations

3.6.1 Appropriately Characterizing DSM and DERs in IRPs

We usually see utilities model DSM in IRPs by explicitly evaluating different levels of savings; we recommend that approach for the Companies as well. In addition, we would recommend:

1. Use of a stakeholder process to support development of DSM inputs for the IRP,
2. Reducing the programs costs for monetizable benefits such as avoided transmission and distribution ("T&D"),[28]
3. Converting the energy savings to the busbar/generator by using the marginal, not average loss rate,
4. Bundling savings consistent with a coherent program or portfolio design, and
5. Modeling levelized, not as-spent, program costs.

EFG staff have participated in stakeholder processes to develop DSM inputs for IRPs in other jurisdictions. We think a similar process could work well in Kentucky and could utilize the existing DSM Advisory Group. This would be separate and apart from a stakeholder process related to the IRP itself. Typically, there is not a lot of overlap between participants in the effort to develop DSM inputs and those that participate in an IRP stakeholder workshop because, while they are related, they implicate different sets of expertise.

3.6.2 Considering Economic Retirement of Coal Plants

Our recommendation for modeling the economic retirement of coal plants is to employ one of two approaches:

1. Allow the capacity expansion model to optimize the retirement date, or
2. Model scenarios that assume a wide range of retirement dates.

We recognize that model run times can pose a challenge for trying to model optimized retirement dates for units and that this first approach may not always be feasible for utilities. If consideration of many

[28] IRP models cannot typically explicitly model all the benefits of DSM, for example, avoided transmission and distribution expenses. However, those avoided costs can be calculated outside of an IRP model and decremented from DSM costs so that they are included in the optimization.

retirement dates creates long run times or intractable problem sizes, we typically see utilities evaluate early retirement dates by modeling a specific, yet broad set of different dates.

To give an example, in its most recent Supplemental IRP filing, Xcel Minnesota modeled a Base or Reference Case that looked at retiring coal units at their current depreciation dates as well as a set of scenarios called the "Early Coal Family."[29] In these scenarios, Xcel looked at one scenario with an early retirement date for Coal Unit A, another scenario that only modeled an early retirement for Coal Unit B, and then another scenario that looked at early retirement of both Coal Units A and B.

3.6.3 Criteria for Selecting Plan

Kentucky's IRP rules state:

> *(5) The resource assessment and acquisition plan shall include a description and discussion of:*
> *…*
> *(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;*
> *(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;* [30]

The Companies' IRP is decidedly vague about these topics. For example, the IRP states "The goal of the resource planning process is to reliably meet customers' around-the-clock energy requirements both in the short-term and long-term at the lowest reasonable cost." It's not clear how the Companies judged "lowest reasonable cost" since only the cost of one plan is given and that plan is clearly not the only feasible plan.

The Resource Screening Analysis says very little about why certain technologies were included in the capacity expansion modeling, but others weren't and doesn't tend to touch on the example criteria given in the IRP rules except to say that technologies such as nuclear are "not cost-effective or not ideal".

---

[29] Docket No. E002/RP-19-368. 2020-2034 Upper Midwest Resource Plan Supplement. June 30, 2020. Page 28.
[30] 807 KAR 5:058, Sec. 5.

4 Reserve Margin Study

4.1 ELDCM Modeling

The Companies sought to test the cost and reliability impacts of coal unit retirements in its Strategic Energy Risk Valuation Model ("SERVM") and Equivalent Load Duration Curve Model ("ELDCM") modeling and to determine the planning reserve margin that would be used in its subsequent capacity expansion modeling, but that analysis falls well short of what we typically see other utilities perform. We address the ELDCM modeling first.

The ELDCM model is spreadsheet based and uses a methodology called "load duration curves" to represent time. Load duration curves order load from highest to lowest load. So rather than a chronological load curve in which load at 10 am follows load at 9 am which follows load at 8 am, etc., load duration curves treat each hour (or other time step) as independent of each other and are only concerned with ordering hours by the size of load. This methodology also assumes that unit characteristics in one hour have no bearing on the performance of those units in any other hour. While it's difficult to capture the impact of generator ramping constraints on rapidly changing demand using this methodology, this approach might suffice for a system that is nearly exclusively thermal, as the Companies' system is at the moment. That is because if a resource is presumed to be online and operating, the output of most generators is unlikely to change frequently from hour to hour. It is not, however, an appropriate methodology to capture reliability impacts of what might be called "time-dependent resources".

For example, the ability of a battery to serve load is very much influenced by its state of charge in the prior hour. In order to incorporate battery storage into this analysis, the Companies would have to develop an a priori assumption about how battery storage would operate, rather than allow the model to dispatch the battery under conditions of system stress, changes in load, etc. An approach using load duration curves, such as the ELDCM analysis, rapidly loses its meaning for these reasons and should not be used for future IRPs.

Furthermore, the ELDCM results demonstrate that this methodology is a poor fit to evaluate the reliability impacts of adding solar to the Companies' system. The Companies merely seem to be assuming that peaking units are backed down when solar is added and that seems to lead to the improbable result that adding solar *erodes* wintertime reliability. In practice, it is quite easy to ramp up peaking units, particularly if they are already committed, so the addition of solar, all else about the portfolio being equal, should have no deleterious impact on reliability. This kind of misalignment between operational practices and the ELDCM methodology would become even more worrisome and complicated to tease out with higher levels of renewables.

4.2 Thermal Unit Retirements

The other major concern with both the ELDCM and SERVM modeling is that the Companies were evaluating the economics and reliability of retiring existing thermal units under limited to no options to replace that capacity. For example, Table 2, below, is the same table in the Companies' Reserve Margin Analysis report that is described as giving "the generation portfolios evaluated in this analysis".[31] We don't appear to have been provided with any SERVM files that would tell us exactly what is in each portfolio. The ELDCM files contain unit codes that are transparent in some cases and unclear in others, so we are taking this table at face value.

The table appears to show that the Company only evaluated portfolios that retired no, one or two existing units without replacement capacity as well as portfolios that added one or two combustion turbines to the Company's existing portfolio without any retirements. The Company did not add any capacity to replace retiring units with one exception discussed below.

Table 2. Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Summer Reserve Margin		Winter Reserve Margin	
		w/o New Solar	w/ New Solar	w/o New Solar	w/ New Solar
Existing + 140 MW SCCT	Add SCCT2	24.6%	27.9%	35.2%	35.2%
Existing + 70 MW of SCCT	Add SCCT1	23.5%	26.8%	34.0%	34.0%
Existing[26]	Existing	22.3%	25.7%	32.8%	32.8%
Retire Brown 8	Ret B8	20.3%	23.7%	30.6%	30.6%
Retire Brown 8-9	Ret B8-9	18.4%	21.7%	28.6%	28.6%
Retire Mill Creek 2	Ret M2	17.5%	20.8%	27.7%	27.7%
Retire Brown 8-10	Ret B8-10	16.4%	19.8%	26.2%	26.2%
Retire Brown 3	Ret B3	15.6%	19.0%	25.7%	25.7%
Retire Brown 8-11	Ret B8-11	14.4%	17.8%	24.0%	24.0%
Retire Brown 3, Mill Creek 2	Ret B3_M2	10.8%	14.1%	20.6%	20.6%

This analytical approach is backwards. If the reason *not* to retire a unit is due to reliability concerns, it follows that one ought to evaluate *replacing* that unit. Effectively, this analysis is showing two things, both of which are self-evident. First, that adding capacity to an existing system increases reliability. We can always increase reliability by adding resources but that also comes with a cost tradeoff. The question of how much reliability to acquire is a socio-economic question, not a technical one. The second thing this shows is that retiring capacity without replacing it negatively impacts reliability. This is the very reason that retirement and replacement are typically evaluated simultaneously, not in the partial approach the Companies have used here.

The Companies, using ELDCM but not SERVM, did add 260 MW of solar to each of these portfolios and recalculate the loss of load expectation ("LOLE"). The LOLE results without and with this solar are replicated here as Table 3 and Table 4. These results suggest that solar would improve summertime reliability, which is when the majority of LOLE risk occurs. However, the ELDCM results cannot be relied upon at least for the winter for the reasons stated above.

[31] Volume II of LG&E and KU 2021 IRP, "2021 IRP Reserve Margin Analysis" at page 24.

Table 3. Reserve Margin Analysis Results without New Solar (ELDCM, 2025 dollars)

Generation Portfolio	Loss of Load Events: Sum	Loss of Load Events: Win	Loss of Load Events: Total	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year): [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year): [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.49	0.29	0.79	63.9	754	768	772	818	832	835
Add SCCT1	0.65	0.37	1.04	56.0	754	769	773	810	825	829
Existing	0.86	0.47	1.36	48.1	755	771	775	803	819	824
Ret B8	1.36	0.70	2.11	47.3	758	772	784	805	819	832
Ret B8-9	2.12	0.99	3.19	46.6	761	780	792	808	827	838
Ret M2	2.73	1.20	4.04	29.4	769	792	802	798	822	832
Ret B8-10	3.27	1.47	4.87	45.9	766	793	802	812	839	848
Ret B3	3.77	1.59	5.52	18.7	767	797	808	786	815	827
Ret B8-11	4.98	2.08	7.27	45.1	774	811	824	819	856	870
Ret B3_M2	10.75	3.59	14.87	0.0	803	869	893	803	869	893

Table 4. Reserve Margin Analysis Results with New Solar (ELDCM, 2025 dollars)

Generation Portfolio	Loss of Load Events: Sum	Loss of Load Events: Win	Loss of Load Events: Total	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year): [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year): [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.20	0.25	0.46	63.9	737	753	755	801	817	819
Add SCCT1	0.27	0.32	0.60	56.0	738	753	755	794	809	811
Existing	0.37	0.41	0.79	48.1	738	754	756	786	802	804
Ret B8	0.60	0.62	1.24	47.3	740	755	760	787	803	808
Ret B8-9	0.97	0.89	1.89	46.6	742	757	766	788	803	812
Ret M2	1.26	1.07	2.38	29.4	748	767	774	777	796	803
Ret B8-10	1.52	1.32	2.91	45.9	745	769	771	791	815	817
Ret B3	1.75	1.43	3.26	18.7	745	770	772	763	789	791
Ret B8-11	2.38	1.88	4.37	45.1	750	776	788	795	821	833
Ret B3_M2	5.43	3.27	8.96	0.0	768	814	838	768	814	838

Despite the limited utility of these analyses, the results do help explain how the Companies can approach the question of bulk system reliability in a more targeted fashion. For example, the SERVM results, given in Table 5, show that the increase in summertime LOLE if Brown 8 is retired is 0.35, but when Brown 9 is also retired, which is identical in size, summer LOLE jumps proportionately more, by 0.59.

Table 5. Reserve Margin Analysis Results without New Solar (SERVM, 2025 Dollars)

Generation Portfolio	Loss of Load Events			[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
	Sum	Win	Total		[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.34	0.25	0.76	63.9	734	757	757	798	820	821
Add SCCT1	0.48	0.33	1.04	56.0	734	755	758	790	811	814
Existing	0.63	0.46	1.42	48.1	735	755	759	783	803	808
Ret B8	0.98	0.69	2.26	47.3	735	757	763	783	805	811
Ret B8-9	1.57	1.03	3.71	46.6	739	763	772	786	810	819
Ret M2	2.14	1.17	4.75	29.4	751	778	789	780	807	818
Ret B8-10	2.38	1.53	5.74	45.9	744	773	784	790	819	830
Ret B3	3.78	1.69	8.05	18.7	752	786	797	771	805	816
Ret B8-11	3.54	2.13	8.64	45.1	752	789	802	797	834	847
Ret B3_M2	10.95	3.57	23.08	0.0	800	858	891	800	858	891

It's tempting to conclude that identical resources would make identical contributions to reliability, but the reality is that most resources make a declining contribution to reliability as more are added. It's also the case that the reliability value of any given unit is dependent on the characteristics of the other units in the portfolio. It's just not possible to capture these interactive effects through IRP modeling and so we would recommend that in future IRPs and CPCNs, that the Companies test economically optimized portfolios of resources in SERVM to determine whether those portfolios meet the LOLE criteria and adjust the portfolios as necessary to meet the minimum LOLE. That way the Company can explicitly consider retirement and replacement decisions together on an economic basis *and* come up with differing portfolios that it can demonstrate are reliable. This is the practice that was used by Public Service Company of New Mexico to evaluate replacement portfolios for its retiring coal units. Astrapé, the Companies' SERVM consultant and vendor, was involved in that case and can provide the Companies with additional details on the approach used.

4.3 Other Recommended Improvements to the SERVM Modeling

Additional improvements to the SERVM modeling would enhance the accuracy and value of these results in future analyses. For example, while it is a positive that the Companies included neighboring regions PJM, MISO, and TVA, the Companies imposed what they term "scarcity pricing" onto market interactions with those regions. The scarcity price curve is shown in Figure 4.

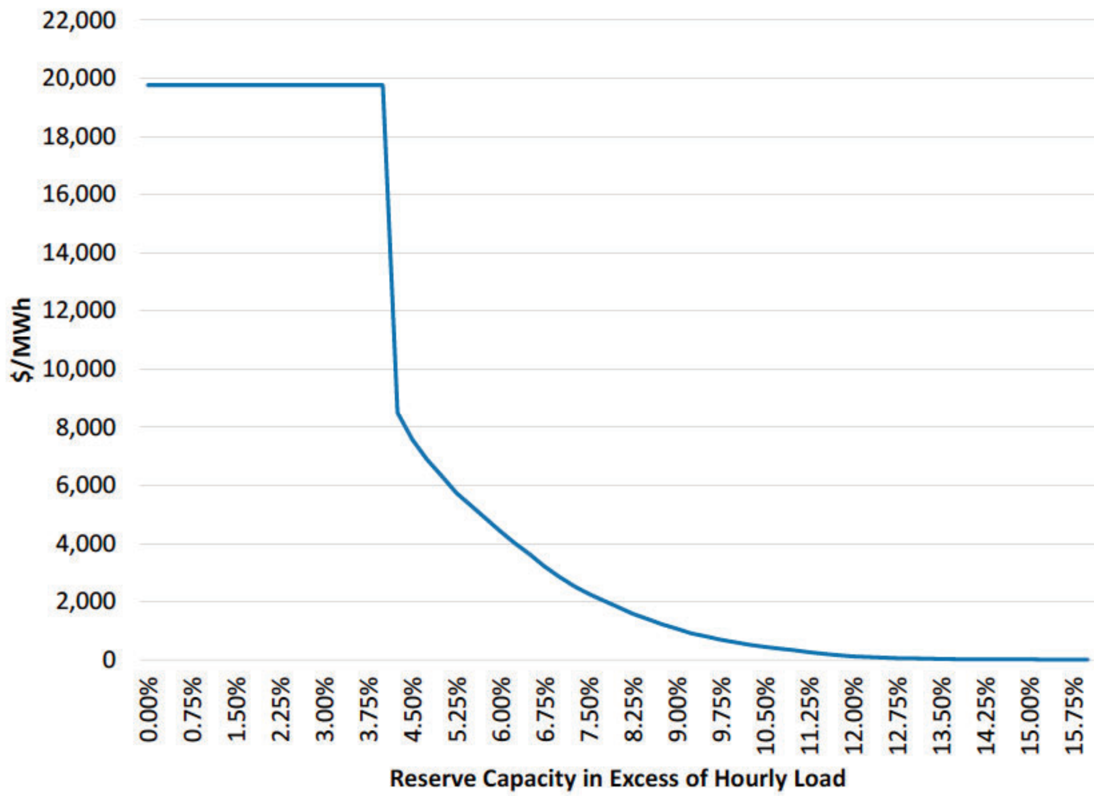


Figure 4. Scarcity Price Curve Used in Reserve Margin Study

This graph shows that in any hour of the SERVM simulation in which the amount of capacity in excess of load falls below 15.25%, a scarcity price would be assessed on any transfers of power between a neighboring region and the Companies' service territory (and we presume vice versa, though it's not clear in the report or modeling files). That price grows quite rapidly from a low of $20 per MWh to $226 per MWh at 11.5% reserve and tops out at $13,760 per MWh at 3.5% excess capacity or less. Indubitably, wholesale power prices rise when demand is high and generation constrained, but we're skeptical that an increase to these levels is warranted. We examined hourly real-time pricing at the LG&E-MISO and the PJM-EKPC interfaces[32] over the last four years as shown in Table 6.

Table 6. Count of Real-Time Prices in Excess of Selected Scarcity Prices in SERVM Modeling, April 2018 – April 2022

Real-Time Price per MWh	MISO-LG&E	PJM-EKPC
>$20	27,265	25,690
>$226	63	49
>$1,000	0	0

[32] There doesn't appear to be interface pricing for PJM-LG&E or it's identical to Eastern Kentucky Power Cooperative's ("EKPC") interface, so we use EKPC-PJM interface pricing here.

While prices were frequently above $20 per MWh, in only 63 and 49 hours, respectively, were prices above $226 per MWh and in no hours were prices above $1,000 per MWh let alone at the maximum scarcity price the Companies modeled of $13,760 per MWh. Furthermore, MISO and PJM both have an energy offer cap of $1,000 per MWh, with limited circumstances under which offers could be higher than that. Even during Winter Storm Uri, when MISO ordered several load sheds, prices never exceeded $444 per MWh.

When asked how these prices were developed the Companies stated, "The pricing curve was developed based on the Companies' actual purchases over a range of reserve conditions and extrapolated to tighter reserve conditions. The values were inflated to 2025 dollars and capped at the cost of unserved energy."[33] The Companies could not provide any documentation of this work, however. And we don't see how a few years of inflation could increase the prices to this degree. To the extent that the Companies continue to rely on SERVM for any economic evaluation of portfolios, the scarcity prices ought to be refined to be consistent with the realities of the conditions governing such power purchases.

An additional improvement would be to simulate changing renewable patterns that are chronologically consistent with the weather conditions underlying load. The SERVM simulations assumed the same solar profile regardless of weather. While this might be an acceptable simplifying assumption for very small amounts of renewables, it does not suffice for portfolios with larger amounts of variable renewable generation in which weather will be a major risk factor.

These are low-hanging fruit improvements to the Companies' reliability modeling. Some other important, but much more difficult to achieve improvements would be to explicitly model energy efficiency with varying savings based on weather and to model correlated forced outages at thermal power plants, e.g, fuel-related outages, to the extent they are not already doing so.

If the Companies choose to continue to rely on planning reserve margins as a measure of reliability rather than explicitly testing the portfolios it models, it would be important to appropriately capture the accredited value of both thermal units and renewables. We tend to pay more attention to non-thermal accreditation practices, but it's important to critically think about thermal accreditation as well. Frequently, it is assumed that a thermal unit's rating need only be adjusted downward for its Equivalent Forced Outage Rate Demand (EFORd) to accurately estimate its accredited value or UCAP value (Unforced Capacity). However, Astrapé recently published a study[34] that demonstrates that even the UCAP approach will overstate the reliability contributions of the average thermal generator. The study proposes additional considerations that would materially impact the accreditation of thermal units, particularly in the wintertime as shown in Table 7.

[33] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors' Question 2.39b.
[34] Dison, Joel et al. "Accrediting Resource Adequacy Value to Thermal Generation." Prepared for Advanced Energy Economy. March 30, 2022.

Table 7. Correlated Outage Impacts on Thermal Accreditation

		Winter Accreditation Impact	Winter Capacity Credit[1]	Summer Accreditation Impact	Summer Capacity Credit
Standard Accounting Practice	Forced Outage Rate	5.0%	95.0%	5.0%	95.0%
Proposed Additional Considerations	Outage Variability	2.7%	92.3%	4.6%	90.4%
	Outage Correlation	2.3%	90.0%		
	Weather Dependent Outages	10.0%	82.3%[2]	5.6%	84.7%
	Fuel Supply Outages[3]	6.2%	76.1%[4]		

5 Companies’ Additional Modeling Analyses Provided in Supplemental Production

5.1 Biden Plan

The Joint Intervenors asked in Supplemental Discovery if “the Companies had evaluated a range of scenarios based on achieving aggressive emission reduction goals?”[35] The Companies provided a copy of PowerPoint slides with the title “Biden Energy Plan: Engineering and financial analysis of achieving 100% carbon-free generation by 2035.” Our review of this modeling is based on these slides, which were the only information provided to the Joint Intervenors through discovery. We did not have the opportunity to ask additional follow up questions or receive the modeling files associated with this analysis.

The Companies’ primary conclusion from this analysis is that “Achieving carbon-free electricity by 2035 with today’s technology seems unlikely and would be wildly expensive.”[36] We have several concerns about the validity and usefulness of the study.

1. The plan to meet a goal of carbon-free electricity by 2035 does not appear to have been optimized and is being compared to a plan that does not seem to include fuel or other non-capital expenditures;
2. The analysis does not seem to be conducted subject to constraints that we would typically see for this analysis, including a reserve margin and operating reserve requirements;
3. The Companies modeled a load profile that was based on 2018 data and didn’t include additional energy efficiency;
4. No inclusion of additional distributed solar capacity;
5. No inclusion of technologies widely assumed to be necessary to achieve the highest levels of carbon reduction such as long duration storage; and
6. Capital cost assumptions for new renewable and storage resources that do not seem to account for existing and likely tax incentives.

The Companies appear to be comparing a plan to reach 100% carbon-free energy by 2035, the “Biden Scenario,” against a plan referred to as “2021 BP” which relies primarily on coal and natural gas. The Companies calculated the cost of new investments for each plan and arrived at the conclusion that the Biden Scenario would require $74 billion in new investments and the 2021 BP would only require $2

[35] Case No. 2021-00393, Companies’ Discovery Response to Joint Intervenors Question 2.52.
[36] Case No. 2021-00393, Companies’ Discovery Response to Joint Intervenors Question 2.52, Attachment 1, slide 32.

billion.[37] The 2021 BP plan costs appear grossly understated in that they don't include fuel or other non-capital expenditures. And the Biden Scenario appears to be extremely costly because it includes extraordinarily unrealistic levels of capacity, over eight times the Companies' peak load on a nameplate basis. The Companies also created portfolios with lower levels of clean energy that seem to suffer from similar flaws.

In the PowerPoint slides, the Companies say that "Thousands of generation portfolios were evaluated to identify lowest-cost options."[38] It's not clear how the Companies could do that. Using a model such as PLEXOS to create thousands of portfolios would be very resource intensive even if only a single year was optimized. And it would be even more resource intensive to generate this number of portfolios by hand. Indeed, whatever methodology the Companies used it would be highly unusual because it included no assumptions for "load uncertainty, reserve margin, or contingency/operating reserves".[39]

One of the confounding results from the analysis is the capacity and energy from new resource additions in the carbon reduction scenarios. Table 8 shows the comparison of the capacity (MW) and energy generated (TWh) from the different resource types across the carbon reduction scenarios. It is curious that the amount of battery storage capacity more than doubles when moving from the 90% Clean to the 100% Clean scenario, yet the energy from battery storage drops from 11.5 TWh in the 90% Clean scenario down to 10 TWh in the 100% Clean scenario. That is, the utilization of battery storage drops in absolute terms as more is added, not just in proportional terms. To move from the 90% Clean scenario to the 100% Clean scenario, the Companies propose replacing 3,300 MW of gas capacity with an additional 12,300 MW of battery storage, 4,900 MW of solar, and 4,700 MW of wind resources and yet the battery storage is utilized less under this scenario *even though* curtailment of renewables nearly quintuples from the 90% Clean Scenario. We did not have access to the modeling results for these scenarios so we cannot explain why this is happening, but it is incongruous and is not the result we would expect to see from a thoughtful optimization exercise.

---

[37] Case No. 2021-00393. Companies Discovery Response to Joint Intervenors Question 2-52, Attachment 1, Powerpoint slide 16.
[38] Case No. 2021-00393. Companies Discovery Response to Joint Intervenors Question 2-52, Attachment 1, Powerpoint slide 14.
[39] Case No. 2021-00393. Companies Discovery Response to Joint Intervenors Question 2-52, Attachment 1, Powerpoint slide 14.

Table 8. Companies' Biden Plan Modeling Results[40]

	2021 BP		50% Clean		75% Clean		90% Clean		100% Clean	
CO2 Emissions (Short Tons)	22.6		6.5		3.1		1.3		0	
	MW	**TWh**	**MW**	**TWh**	**MW**	**TWh**	**MW**	**TWh**	**MW**	**TWh**
Load	6,009	31	6,009	31.0	6,009	31.0	6,009	31.0	6,009	31
Coal	2,900	15	--	--	--	--	--	--	0	0
Gas	4,076	16	4,300	15.4	3,700	7.7	3,300	3.1	0	0
Solar	10	0	7,200	15.4	9,300	19.9	13,100	28.0	18,000	39
Wind	--	--	700	1.5	3,800	8.4	4,300	9.5	9,000	19
Hydro	134	0.3	134	0.3	134	0.3	134	0.3	134	0.3
Battery Storage	--	--	3,400	7.8	6,100	9.7	10,700	11.5	23,000	10
Unused Solar/Wind	--	--	--	10.7	--	1.8	--	5.7	--	24
Battery/Inverter Losses	--	--	--	5.6	--	3.6	--	4.3	--	2

The PowerPoint slides also seem to indicate that the Companies used the 2018 peak demand energy data for the 2035 modeling and that the same load assumptions were modeled for the 2021 BP and Biden Plan scenarios. This is confusing because the Companies also include a slide that provide key items[41] from the Biden Plan. Among those key items are increased energy efficiency standards, in addition to distributed and community solar. If the Companies had incorporated increased energy efficiency savings assumptions and lower energy use from customers with distributed solar, then the load forecasts would not be the same across these plans.

One of our other concerns about this exercise is that the Companies assume that the replacement resource options are only solar, Kentucky-based wind, four-hour battery storage, and hydrogen combined cycle resources. We are not sure why the Companies did not evaluate long duration storage, 8- or 10-hour durations or even longer, for this exercise, especially since the Companies included 8-hour battery storage resources in its IRP modeling. In several of the PowerPoint slides the Companies mention that 60% of LG&E and KU winter demand occurs at night.[42] This is just one reason that the Companies might utilize longer duration battery storage during times when solar and wind may not be available.

---

[40] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.52, Attachment 1, slide 4.
[41] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.52, Attachment 1, slide 2.
[42] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.52. Attachment 1, slide 9.

5.2 Solar Intermittency Study

In late 2020, the Companies produced a study of the impacts of intermittent solar and concluded that:

> *• For ≤ 500 megawatts (MW) of solar, the existing LG&E and KU generation portfolio—without operational changes—can regulate output to meet demand with negligible imbalances.*
> *• Solar penetration between 500 and 1,000 MW would require some minor changes to generation unit operation, dispatch, and unit commitments with minor costs for generation to match load in real time.*
> *• Solar penetration above 1,000 MW—to prevent significant imbalances—would require changes to the existing generation portfolio, including the retirement of older coal-fired generating units and addition of more-agile natural gas combined cycle units. As coal units are replaced with combined cycle units, the solar hosting capacity limit will be higher than 1,000 MW.*
> *• If solar capacity were properly dispersed across the transmission system, there are no indications that solar penetration of ≤1,000 MW would create transmission problems. However, individual transmission system components, lines and transformers, are most-sensitive at the Point of Interconnection (POI) and neighboring regions of the system; thus, a detailed power flow analysis and circuit study is required for each project.*[43]

The imbalances associated with 1,000 MW or more of solar seem to be predicated on the count of anticipated, 5-minute interval imbalances, both positive and negative.[44] At 1,000 MW of solar, the Companies anticipate six hundred 5-minute and forty-nine 5-minute intervals with a positive or negative imbalance, respectively. Put another way, generation would exceed load 1.4% of the time and generation would fall short of load 0.56% of the time.[45] However, it's not clear what level of imbalance the Companies would consider acceptable and why. Is zero imbalance the goal? If so, that is not a realistic standard to impose.

The North American Electric Reliability Corporation ("NERC") balancing standards are assessed on a greater than 5-minute basis[46] and allow for both positive and negative excursions for specified durations before a violation would occur. Historic imbalances, known as Area Control Error ("ACE") are recorded at 10-minute and 1-minute intervals. ACE data reported by the Companies show that positive and negative imbalances are the norm for system operations, see Figure 5, below. Note that these are not

---

[43] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.60, Attachment 1, page 2.
[44] Case No. 2021-00393, Companies' Discovery Response to Joint Intervenors Question 2.60, Attachment 1, pages 27 and 32.
[45] In practice there is also a small bias to maintain frequency, but that is not included in this example to simplify the explanation.
[46] See https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

necessarily violations, which would be determined by measuring the duration and magnitude of ACE against the Companies' NERC obligations.

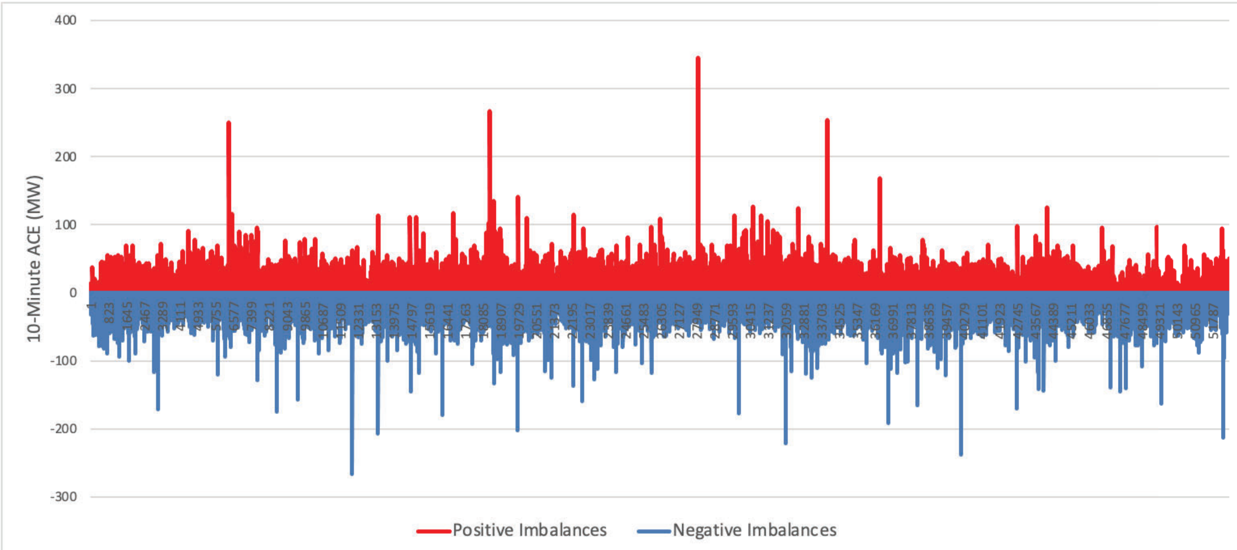


Figure 5. Actual LGEE 10-minute Area Control Error (Imbalance) for 2021[47]

At no point in 2021 was the Companies' system perfectly in balance on either a 10-minute or 1-minute interval. Without additional information about the rationale for the claim that there are significant imbalances with 1,000 MW of solar on the Companies' system and more information about the analysis performed, it appears that the Companies are imposing a standard on solar that they cannot meet today with the existing portfolio.

Finally, the Companies note that "The addition of lithium-ion energy storage, which respond[s] instantaneously, can mitigate problems caused by solar intermittency including short-term generation imbalances, and transmission support with auto frequency-watt and autonomous volt-Var functionality."[48] Certainly at 1,000 MW of solar and for a system of the Companies' size, there may be economic reasons to add battery storage rather than curtail solar generation. But this statement suggests to us that the Companies failed to consider the impact of applying automatic generation control ("AGC") systems[49] to solar and failed to consider the capabilities of modern inverters which, when correctly specified, allow inverter-based resources (battery storage, wind, *and* solar) to provide reactive power and perform voltage regulation regardless of whether they are operating or not.

---

[47] http://www.oasis.oati.com/LGEE/index.html
[48] Case No. 2021-00393. Companies Discovery Response to Joint Intervenors Question 2-60. Attachment 1 page 2.
[49] See this NREL report for additional information on the capabilities of AGC systems applied to renewables: https://www.nrel.gov/docs/fy19osti/73866.pdf.

Thus, the solar intermittency study seems to give a picture of the impact of adding large amounts of solar that is out of sync with applicable balancing standards, current operating conditions, and the capabilities of modern renewable and storage systems.

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:

1. Encourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs and assumptions including, but not limited to:
    a. The Companies' reserve margin study;
    b. The development and modeling of the portfolios considered in the IRP;
    c. The manner in which unit retirement is evaluated;
    d. The RTO membership analysis;
    e. The source of and manner in which new resource costs and supply are developed, e.g. demand-side management and other distributed energy resources; and
    f. The modeling tools used in the development of the IRP.
2. Encourage the Companies to negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package(s) and encourage the Companies to absorb the cost of these licensing fees.
3. Clarify that upon filing of an IRP, LG&E/KU should make available, on request and ideally simultaneously with filing of the IRP, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual(s).
4. Recommend that the Companies adopt the typical practice of using a single model for capacity expansion and production cost modeling.
5. Direct the Companies to model a full planning period and not just a single year.
6. Encourage the Companies to document their analytical work so that it clearly conveys the steps taken and information relied upon.
7. Encourage the Companies to limit out-of-model adjustments and include as many system costs in the model as is feasible.
8. Direct the Companies to economically evaluate all potentially cost-effective resource options available to it, specifically including a wide range of levels of new and expanded Demand-Side Management ("DSM") and other distributed energy resources ("DERs") such as distributed solar and storage. The DSM levels should be developed through the meaningful and participatory collaboration of the DSM Advisory Group as previously recommended by staff.
9. Direct the Companies to consider key issues or uncertainties potentially impacting their resource plan, particularly including analysis of the impacts of a CO_2 price and meeting a significant emission reduction goal such as PPL's corporate goal on the Companies' resource plans.
10. Encourage the Companies to cease use of the Equivalent Load Duration Curve Model ("ELDCM") for reliability modeling.

Our recommendations are intended to provide feedback on how the Companies can transition to an IRP approach that is typical or even best in class relative to its peer utilities.

Attachment A

Anna Sommer
Principal

Professional Summary

Anna Sommer is a principal of Energy Futures Group in Hinesburg, Vermont. She has nearly 20 years' experience working on a wide variety of energy planning related issues. Her primary focus is on all aspects of integrated resource planning (IRP) including capacity expansion and production costing simulation, scenario and sensitivity construction, modeling of supply and demand side resources, and review and critique of forecast inputs such as fuel prices, wholesale market prices, load forecasts, etc. Additionally, she has experience with various aspects of DSM planning including construction of avoided costs and connecting IRPs to subsequent DSM plans. Anna has had formal training on the Aurora, EnCompass, and Strategist models and has reviewed modeling performed using numerous models including Aurora, EnCompass, Capacity Expansion Model, PLEXOS, PowerSimm, PROSYM, PROMOD, RESOLVE, SERVM, Strategist, and System Optimizer. She has provided expert testimony in front of utility commissions in Indiana, Michigan, Minnesota, Montana, New Mexico, North Carolina, Puerto Rico, and South Carolina, and South Dakota.

Experience

2019-present: Principal, Energy Futures Group, Hinesburg, VT
2010-2019: President, Sommer Energy, LLC, Canton, NY
2007-2008: Project Manager, Energy Solutions, Oakland, CA
2003-2007: Research Associate, Synapse Energy Economics, Cambridge, MA

Education

M.S. Energy and Resources, University of California Berkeley, 2010

Master's Project: *The Water and Energy Nexus: Estimating Consumptive Water Use from Carbon Capture at Pulverized Coal Plants with a Case Study of the Upper Colorado River Basin*

B.S., Economics and Environmental Studies, Tufts University, 2003

Additional training

Graduate coursework in Data Analytics – Clarkson University, 2015-2016.
Graduate coursework in Civil Engineering and Applied Mechanics – McGill University, 2010.
Research Experience in Carbon Sequestration (RECS), U.S. Department of Energy, 2009.

Selected Projects

- MISO Environmental Sector. Supporting the Environmental Sector of MISO during the process of redesigning MISO's resource adequacy construct including advising on the manner in which the construct would influence integrated resource plans in the MISO footprint. (2021 to present)

- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)
- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and Strategist modeling in support of that evaluation. (2019 to present) Evaluation of Minnesota Power Company's proposal to build a new natural gas combined cycle power plant and Strategist modeling of alternatives to the plant. Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2018) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2016) Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2015) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2014) Comments regarding Xcel Energy's Sherco 1 and 2 Life-Cycle Management Study. Comments regarding Minnesota Power's proposal to retrofit Boswell Unit 4. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs. (2013) Evaluation of Otter Tail Power's plan to diversify its baseload resources. Comments regarding Minnesota Power's "Baseload Diversification Study" – a resource planning exercise examining the use of fuels other than coal to serve baseload needs. (2012) Comments regarding IPL's integrated resource plan to comply with pending EPA regulations and meet future capacity and energy needs. (2011) Evaluation of a proposal by seven utilities to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation. (2006)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Earthjustice. Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- Citizens Action Coalition of Indiana. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. (2020 to present) Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. (2020) Advising stakeholders on stakeholder workshops in preparation for Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs. Evaluation of Indianapolis Power & Light's proposal to offer DSM programs to its customers. Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Indiana Michigan Power's proposal to offer DSM programs to its customers. (2019 to present) Comments regarding Duke Energy Indiana's integrated resource plan to meet future energy and capacity needs. Comments regarding Indiana Michigan Power's integrated resource plan to meet future energy and capacity needs. (2019) Comments on Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2019) Evaluation of Southern Indiana Gas and Electric's

proposal to build a new natural gas combined cycle power plant. (2018) Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. Comments regarding Southern Indiana Gas and Electric Company's integrated resource plans to meet future energy and capacity needs. Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. Comments regarding Northern Indiana Public Service Company's integrated resource plan to meet future energy and capacity needs. (2017) Comments regarding Duke Energy Indiana and Indiana Michigan Power's integrated resource plans to meet future energy and capacity needs. (2016)

- Environmental Law and Policy Center. Evaluation of DTE Energy's 2019 Integrated Resource Plan modeling and Strategist modeling in support of that evaluation. (2019)
- New Energy Economy. Evaluation of Public Service Company of New Mexico's Strategist modeling of coal plant retirement scenarios. (2017)
- Institute for Energy Economics and Financial Analysis. Evaluation of Puerto Rico Electric Power Authority's plan to build an offshore LNG port. (2017) Evaluation of Puerto Rico Electric Power Authority's proposal to meet future energy and capacity needs.

Selected Publications

The Husker Energy Plan: A New Energy Plan for Nebraska, prepared by Anna Sommer, Tyler Comings, and Elizabeth Stanton for the Nebraska Wildlife Federation. January 16, 2018.

Pennsylvania Long-Term Renewables Contracts Benefits and Costs, prepared by Elizabeth Stanton, Anna Sommer, Tyler Comings, and Rachel Wilson for the Mid-Atlantic Renewable Energy Coalition. October 27, 2017.

"Pursue Carbon Capture and Utilization of Storage," "Establish Energy Savings Targets for Utilities," and "Tax Carbon Dioxide Emissions," in Implementing EPA's Clean Power Plan: A Menu of Options, prepared by Anna Sommer for the National Association of Clean Air Agencies and the Regulatory Assistance Project. June 7, 2015.

Overpaying and Underperforming: The Edwardsport IGCC Project, prepared by Anna Sommer for Citizens' Action Coalition, Save the Valley, Valley Watch, and Sierra Club. February 3, 2015.

Public Utility Regulation Without the Public: The Alabama Public Service Commission and Alabama Power, prepared by David Schlissel and Anna Sommer for Arise Citizens' Policy Project. March 1, 2013.

A Texas Electric Capacity Market: The Wrong Tool for a Real Problem, prepared by Anna Sommer and David Schlissel for Public Citizen of Texas. February 12, 2013.

Independent Administration of Energy Efficiency Programs: A Model for North Carolina, prepared by David Nichols, Anna Sommer, and William Steinhurst for Clean Water for North Carolina, April 13, 2007.

Integrated Portfolio Management in a Restructured Supply Market, prepared by Paul Chernick, Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommer, and Kenji Takahashi. June 30, 2006.

Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William

Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer, and Ezra Hausman for the Delaware Public Service Commission staff. March 8, 2006.
"Assessment of Carbon Sequestration Feasibility and Markets," by Anna Sommer and William Steinhurst, in Mohave Alternatives and Complements Study, a Sargent & Lundy and Synapse Energy Economics, Inc., report prepared for Southern California Edison. February 2006.
Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen, and Anna Sommer for the New Brunswick Department of Energy. October 2005.
Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald as a Synapse Energy Economics, Inc. report. September 20, 2005.
Potential Cost Impacts of a Vermont Renewable Portfolio Standard, prepared by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer as a Synapse Energy Economics, Inc. report for the Vermont Public Service Board. October 16, 2003.

Presentations and Articles

"Practical Strategies for the Electricity Transition." A presentation at Energy Finance 2019. June 18, 2019.
"Carbon Capture and Storage." A presentation at Energy Finance 2018. March 13, 2018.
"Puerto Rico's Electric System, Before and After Hurricane Maria." A webinar with Cathy Kunkel on behalf of the Institute for Energy Economics and Financial Analysis. October 24, 2017.
"Rebutting Myths About Energy Efficiency." A presentation at the Beyond Coal to Clean Energy Conference sponsored by Sierra Club and Energy Foundation. October 8, 2015.
"The Energy and Water Nexus: Carbon Capture and Water." A presentation at the Water and Energy Sustainability Symposium. September 28, 2010.
"Carbon Sequestration." A presentation to Vermont Energy Investment Corporation. August 17, 2009.
"Carbon Dioxide Emissions Costs and Electricity Resource Planning." A presentation before the New Mexico Public Regulation Commission with David Schlissel. March 28, 2007.
"Electricity Supply Prices in Deregulated Markets – The Problem and Potential Responses." A presentation at the NASUCA Mid-Year Meeting with Rick Hornby and Ezra Hausman. June 13, 2006.
"IGCC: A Public Interest Perspective." A presentation at the Electric Utilities Environmental Conference 2006. January 24, 2006.
Woolf, Tim, Anna Sommer, John Nielsen, David Barry and Ronald Lehr. "Managing Electric Industry Risk with Clean and Efficient Resources," The Electricity Journal, Volume 18, Issue 2, March 2005.
Woolf, Tim, and Anna Sommer. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York," Local Environment, Volume 9, Number 1, February 2004.

Professional Affiliations

Board Member, **Public Utility Law Project of New York,** 2018 – present

Board Member, **Community Development Program of St. Lawrence County,** 2017 – present

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 315-386-3834 | asommer@energyfuturesgroup.com

Anna Sommer
Principal

ENERGY FUTURES GROUP

Professional Summary

Anna Sommer is a principal of Energy Futures Group in Hinesburg, Vermont. She has nearly 20 years' experience working on a wide variety of energy planning related issues. Her primary focus is on all aspects of integrated resource planning (IRP) including capacity expansion and production costing simulation, scenario and sensitivity construction, modeling of supply and demand side resources, and review and critique of forecast inputs such as fuel prices, wholesale market prices, load forecasts, etc. Additionally, she has experience with various aspects of DSM planning including construction of avoided costs and connecting IRPs to subsequent DSM plans. Anna has had formal training on the Aurora, EnCompass, and Strategist models and has reviewed modeling performed using numerous models including Aurora, EnCompass, Capacity Expansion Model, PLEXOS, PowerSimm, PROSYM, PROMOD, RESOLVE, SERVM, Strategist, and System Optimizer. She has provided expert testimony in front of utility commissions in Indiana, Michigan, Minnesota, Montana, New Mexico, North Carolina, Puerto Rico, and South Carolina, and South Dakota.

Experience

2019-present: Principal, Energy Futures Group, Hinesburg, VT
2010-2019: President, Sommer Energy, LLC, Canton, NY
2007-2008: Project Manager, Energy Solutions, Oakland, CA
2003-2007: Research Associate, Synapse Energy Economics, Cambridge, MA

Education

M.S. Energy and Resources, University of California Berkeley, 2010

Master's Project: *The Water and Energy Nexus: Estimating Consumptive Water Use from Carbon Capture at Pulverized Coal Plants with a Case Study of the Upper Colorado River Basin*

B.S., Economics and Environmental Studies, Tufts University, 2003

Additional training

Graduate coursework in Data Analytics – Clarkson University, 2015-2016.
Graduate coursework in Civil Engineering and Applied Mechanics – McGill University, 2010.
Research Experience in Carbon Sequestration (RECS), U.S. Department of Energy, 2009.

Selected Projects

- MISO Environmental Sector. Supporting the Environmental Sector of MISO during the process of redesigning MISO's resource adequacy construct including advising on the manner in which the construct would influence integrated resource plans in the MISO footprint. (2021 to present)

- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)
- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and Strategist modeling in support of that evaluation. (2019 to present) Evaluation of Minnesota Power Company's proposal to build a new natural gas combined cycle power plant and Strategist modeling of alternatives to the plant. Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2018) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2016) Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2015) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2014) Comments regarding Xcel Energy's Sherco 1 and 2 Life-Cycle Management Study. Comments regarding Minnesota Power's proposal to retrofit Boswell Unit 4. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs. (2013) Evaluation of Otter Tail Power's plan to diversify its baseload resources. Comments regarding Minnesota Power's "Baseload Diversification Study" – a resource planning exercise examining the use of fuels other than coal to serve baseload needs. (2012) Comments regarding IPL's integrated resource plan to comply with pending EPA regulations and meet future capacity and energy needs. (2011) Evaluation of a proposal by seven utilities to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation. (2006)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Earthjustice. Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- Citizens Action Coalition of Indiana. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. (2020 to present) Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. (2020) Advising stakeholders on stakeholder workshops in preparation for Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs. Evaluation of Indianapolis Power & Light's proposal to offer DSM programs to its customers. Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Indiana Michigan Power's proposal to offer DSM programs to its customers. (2019 to present) Comments regarding Duke Energy Indiana's integrated resource plan to meet future energy and capacity needs. Comments regarding Indiana Michigan Power's integrated resource plan to meet future energy and capacity needs. (2019) Comments on Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2019) Evaluation of Southern Indiana Gas and Electric's

proposal to build a new natural gas combined cycle power plant. (2018) Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. Comments regarding Southern Indiana Gas and Electric Company's integrated resource plans to meet future energy and capacity needs. Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. Comments regarding Northern Indiana Public Service Company's integrated resource plan to meet future energy and capacity needs. (2017) Comments regarding Duke Energy Indiana and Indiana Michigan Power's integrated resource plans to meet future energy and capacity needs. (2016)

- Environmental Law and Policy Center. Evaluation of DTE Energy's 2019 Integrated Resource Plan modeling and Strategist modeling in support of that evaluation. (2019)
- New Energy Economy. Evaluation of Public Service Company of New Mexico's Strategist modeling of coal plant retirement scenarios. (2017)
- Institute for Energy Economics and Financial Analysis. Evaluation of Puerto Rico Electric Power Authority's plan to build an offshore LNG port. (2017) Evaluation of Puerto Rico Electric Power Authority's proposal to meet future energy and capacity needs.

Selected Publications

The Husker Energy Plan: A New Energy Plan for Nebraska, prepared by Anna Sommer, Tyler Comings, and Elizabeth Stanton for the Nebraska Wildlife Federation. January 16, 2018.
Pennsylvania Long-Term Renewables Contracts Benefits and Costs, prepared by Elizabeth Stanton, Anna Sommer, Tyler Comings, and Rachel Wilson for the Mid-Atlantic Renewable Energy Coalition. October 27, 2017.
"Pursue Carbon Capture and Utilization of Storage," "Establish Energy Savings Targets for Utilities," and "Tax Carbon Dioxide Emissions," in Implementing EPA's Clean Power Plan: A Menu of Options, prepared by Anna Sommer for the National Association of Clean Air Agencies and the Regulatory Assistance Project. June 7, 2015.
Overpaying and Underperforming: The Edwardsport IGCC Project, prepared by Anna Sommer for Citizens' Action Coalition, Save the Valley, Valley Watch, and Sierra Club. February 3, 2015.
Public Utility Regulation Without the Public: The Alabama Public Service Commission and Alabama Power, prepared by David Schlissel and Anna Sommer for Arise Citizens' Policy Project. March 1, 2013.
A Texas Electric Capacity Market: The Wrong Tool for a Real Problem, prepared by Anna Sommer and David Schlissel for Public Citizen of Texas. February 12, 2013.
Independent Administration of Energy Efficiency Programs: A Model for North Carolina, prepared by David Nichols, Anna Sommer, and William Steinhurst for Clean Water for North Carolina, April 13, 2007.
Integrated Portfolio Management in a Restructured Supply Market, prepared by Paul Chernick, Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommer, and Kenji Takahashi. June 30, 2006.
Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William

Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer, and Ezra Hausman for the Delaware Public Service Commission staff. March 8, 2006.
"Assessment of Carbon Sequestration Feasibility and Markets," by Anna Sommer and William Steinhurst, in Mohave Alternatives and Complements Study, a Sargent & Lundy and Synapse Energy Economics, Inc., report prepared for Southern California Edison. February 2006.
Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen, and Anna Sommer for the New Brunswick Department of Energy. October 2005.
Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald as a Synapse Energy Economics, Inc. report. September 20, 2005.
Potential Cost Impacts of a Vermont Renewable Portfolio Standard, prepared by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer as a Synapse Energy Economics, Inc. report for the Vermont Public Service Board. October 16, 2003.

Presentations and Articles

"Practical Strategies for the Electricity Transition." A presentation at Energy Finance 2019. June 18, 2019.
"Carbon Capture and Storage." A presentation at Energy Finance 2018. March 13, 2018.
"Puerto Rico's Electric System, Before and After Hurricane Maria." A webinar with Cathy Kunkel on behalf of the Institute for Energy Economics and Financial Analysis. October 24, 2017.
"Rebutting Myths About Energy Efficiency." A presentation at the Beyond Coal to Clean Energy Conference sponsored by Sierra Club and Energy Foundation. October 8, 2015.
"The Energy and Water Nexus: Carbon Capture and Water." A presentation at the Water and Energy Sustainability Symposium. September 28, 2010.
"Carbon Sequestration." A presentation to Vermont Energy Investment Corporation. August 17, 2009.
"Carbon Dioxide Emissions Costs and Electricity Resource Planning." A presentation before the New Mexico Public Regulation Commission with David Schlissel. March 28, 2007.
"Electricity Supply Prices in Deregulated Markets – The Problem and Potential Responses." A presentation at the NASUCA Mid-Year Meeting with Rick Hornby and Ezra Hausman. June 13, 2006.
"IGCC: A Public Interest Perspective." A presentation at the Electric Utilities Environmental Conference 2006. January 24, 2006.
Woolf, Tim, Anna Sommer, John Nielsen, David Barry and Ronald Lehr. "Managing Electric Industry Risk with Clean and Efficient Resources," The Electricity Journal, Volume 18, Issue 2, March 2005.
Woolf, Tim, and Anna Sommer. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York," Local Environment, Volume 9, Number 1, February 2004.

Professional Affiliations

Board Member, **Public Utility Law Project of New York,** 2018 – present

Board Member, **Community Development Program of St. Lawrence County,** 2017 – present

Energy Futures Group, Inc

PO Box 587, Hinesburg, VT 05461 – USA | 315-386-3834 | asommer@energyfuturesgroup.com

Attachment B

Chelsea Hotaling
Consultant

ENERGY FUTURES GROUP

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 an IRP analyses and has critiqued IRP modeling performed using Aurora, Plexos, PowerSimm, and System Optimizer. Chelsea has experience working with numerous software programs including Python, R, and Stata. She has submitted expert testimony before public utility commissions in Colorado and Michigan.

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, 2007

Experience

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

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

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

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

Selected Projects

- The Council for the New Energy Economics. Participating in Evergy's integrated resource plan stakeholder workshops and performing EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2019 to 2021)
- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

Energy Futures Group, Inc

PO Box 587, Hinesburg, VT 05461 – USA | 802-227-2316| @chotaling@energyfuturesgroup.com

- 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)
- Earth Justice. 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)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Citizens Action Coalition of Indiana. 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 Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (December 2019). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2019) Evaluation of Southern Indiana Gas and Electric's proposal to build an 850 MW gas combined cycle facility. (August 2018)
- 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

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.

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 802-227-2316| chotaling@energyfuturesgroup.com

Chelsea Hotaling
Consultant

ENERGY FUTURES GROUP

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 an IRP analyses and has critiqued IRP modeling performed using Aurora, Plexos, PowerSimm, and System Optimizer. Chelsea has experience working with numerous software programs including Python, R, and Stata. She has submitted expert testimony before public utility commissions in Colorado and Michigan.

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, 2007

Experience

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

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

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

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

Selected Projects

- The Council for the New Energy Economics. Participating in Evergy's integrated resource plan stakeholder workshops and performing EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2019 to 2021)
- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 802-227-2316| @chotaling@energyfuturesgroup.com

- 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)
- Earth Justice. 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)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Citizens Action Coalition of Indiana. 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 Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (December 2019). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2019) Evaluation of Southern Indiana Gas and Electric's proposal to build an 850 MW gas combined cycle facility. (August 2018)
- 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

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.

Attachment C








Production Cost Planning Model Evaluation - 2019

Why Do We Need to Change Production Cost Models?

- Our current models, Prosym and System Optimizer, are no longer supported by ABB. Future resource planning will require more advanced production cost model features such as:
  - Climate Goals
    - CO_2 tons cap with full hourly unit dispatch
  - Detailed ancillary services modeling
    - Prosym requires combining some ancillary services
  - Better optimized pumped storage and battery operation
    - Maximize the value of energy storage
  - Solar combined with battery storage
    - Solar provides all charging energy for the battery
  - Better handling of coal and natural gas fuel switching for the coal steam units
    - Model changes in capacity, O&M cost, heat rate, etc. using different fuels
  - Combined cycle multi-mode operation

Which Models Did We Evaluate?

- ABB introduced new models called **Capacity Expansion** and **Portfolio Optimization** in 2016
  - Duke started evaluation of the new ABB models in 2017 and continued through early 2019
  - Portfolio Optimization is too slow to solve the combined DEC and DEP system
  - Newest version still has issues modeling all required unit characteristics
  - User interface is not easy to use and documentation is lacking

- Two other models were selected to provide a comparison to the ABB models
  - **PLEXOS** by Energy Exemplar
  - **Encompass** by Anchor Power Solutions

- New models use Mixed Integer Linear Programming
  - Minimize production costs while satisfying constraints such as unit run times and ancillary service requirements
  - Flexible constraint logic set by user – solution optimality vs. model solve time
  - Generally better handling of limitations on energy, fuel, and emissions

What Scenarios Did We Run?

- **Capacity Expansion and Production Cost**
  - No CO2 cost
  - CO2 tax
  - CO2 mass cap
  - Renewable portfolio standard
  - Retirement of existing units
  - Ancillary services

- **Production Cost Only**
  - Dual fuel option for coal units
  - Pumped storage and battery operation – detailed outputs
  - Ancillary services – detailed outputs
  - Avoided cost calculation (peak and off peak)

What Evaluation Criteria Did We Consider?

	Encompass	PLEXOS	ABB
Portfolio cost • Fuel cost, VOM, emission cost, dump and unserved energy cost	✓	✓	✓
Unit operation • Capacity factors, starts, storage charging and discharging, ancillary service contribution, dual fuel operation	✓	✓	✓
Model performance • Solve time and simplifications necessary to solve solution in a reasonable amount of time	✓	✓	✗
Ease of use • Data input and results output processes • Multi-user workflow	✓	✓	✗
Documentation • Process flow, inputs and outputs	✓	✓	✗

Which Model Did We Choose?

Encompass was selected as our new production cost and capacity expansion model

- Lower overall production costs than Prosym
  - Unit operations were similar between all models
  - Expansion plans minimized capacity reserve margin slightly better than PLEXOS
  - Encompass and PLEXOS are equally good at maximizing the value of pumped storage and batteries
- Slightly faster than PLEXOS in most scenarios
- User interface is easy to use
  - Data input and output are simple
  - Multiple users can edit data at the same time
  - Good documentation but help file needs to be expanded to include some newer features
- User base is limited and company is very small, leveraging other agreements
  - All Minnesota regulated electric utilities will use Encompass for future IRP filings

What Are the Next Steps?

- Anchor Power Solutions will create DEI, DEK and DEF databases from our existing model inputs
  - Only Carolinas database was created for the evaluation process
- Training for all planning group employees
- Benchmark Encompass results to current model runs
- Decision regarding use of Encompass for the 2020 IRP expected to be made by early June
- Expand model capabilities
  - Eastern Interconnect expansion plan
    - New plans based on scenarios such as CO_2 tax, high RPS requirements, climate goals
  - Zonal
    - Power prices for Duke regions
    - RTO studies
  - Nodal (Available 2021)
    - DC power flow/LMP
    - Transmission impacts of adding more solar

Appendix – How We Scored Each Model

- Scoring matrix based on a 1-5 scale with 5 being the highest
- Four categories – Capacity Expansion, Production Cost, Software Quality, Contract
  - Each category is broken down into several items
  - Models were given a score for each item
  - The importance of each scoring item was also weighted on a 1-5 scale
  - Total for each item is the score multiplied by the weight
- Encompass had the highest overall score followed closely by PLEXOS

Scoring Matrix

Capacity Expansion

	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Quality of Expansion Plan	5	5	5	5	25	25	25	PLEXOS plan has a slightly higher average reserve margin in CO2 Tax, but very small differences.
Total PVRR	4	5	4	3	12	15	12	ABB ignores ancillary services in capacity expansion runs. PLEXOS only uses nominal fixed charge rate. Encompass is more flexible.
Solution Time	5	5	5	4	20	20	20	Fast solutions from all models.
Unit Operation	4	5	5	4	16	20	20	Encompass and PLEXOS can model dual-fuel and solar/storage combo in capacity expansion runs. Encompass is the only model that incorporates start costs in capacity expansion runs.
Total - Capacity Expansion					73	80	77	

Production Cost

	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Total PVRR	3	5	5	5	15	25	25	Encompass and PLEXOS costs are very close.
Unit Operation	3	5	5	5	15	25	25	All models handle storage/solar combination and dual-fuel units. ABB was unable to model all unit operation constraints. PLEXOS allowed tight control of charging and discharging for the storage/solar combination. Encompass allowed tight control of charging but allowed total output of the combination to exceed the inverter limit in a few instances.
Solution Time	1	5	5	5	5	25	25	ABB performance is not competitive with the other models despite several years of development.
Total - Production Cost					35	75	75	

Scoring Matrix (cont)

Software Quality	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Ease of Use	1	5	5	5	5	25	25	ABB is difficult to learn for new users. Encompass uses familiary terminology to our current tools. PLEXOS terminology is different, but not too hard to learn.
Documentation	2	4	5	4	8	16	20	PLEXOS has an excellent help file system built into the interface. Encompass help is good, but has some missing features. ABB documentation is low quality.
Data Sharing	2	5	4	4	8	20	16	Easy to export Encompass inputs to spreadsheets for sharing with internal and external customers/stakeholders. PLEXOS inputs can be copied to Excel easily. ABB views can be exported to Excel, but only a few inputs at a time.
Multi-user Workflow	4	5	4	5	20	25	20	Encompass and ABB use a SQL Server database for a full multi-user environment. PLEXOS has a data management system that requires manual user coordination.
Auditing Data Changes	3	5	4	3	9	15	12	ABB requires all data changes to be viewed within the user interface while the other models can export inputs to spreadsheets or built-in comparison tools. Encompass shows the name of the user and the date of each data input change. PLEXOS and ABB do not provide any data change audit trail.
Exporting Results	1	5	5	5	5	25	25	Encompass is easy to export all results to Excel, but can't handle many years of hourly outputs. PLEXOS has a flexible data reporting tool, but can require multiple queries per run. Getting results out of ABB model is very slow, memory intensive and hasn't improved much in the last several versions. Efficient handling of hourly output will be essential in creating avoided energy costs for the Carolinas due to the multi-time-period rate design and the frequency of update.
Data Security	4	4	4	3	12	12	12	PLEXOS makes an automatic backup of the database when the file is opened. ABB and Encompass use SQL Server and would use database tools to recover from corruption.
Backup and Recovery	5	5	5	3	15	15	15	PLEXOS data is stored on file shares and are backed up each day. ABB and Encompass use a SQL Server database that is automatically backed up.
Scaling Up/Extending	4	4	5	3	12	12	15	Encompass and ABB can handle multiple user and concurrent runs. PLEXOS has an API that can be used to extend the capabilities of the model.
Total - Software Quality					94	165	160	
Total All Categories					**202**	**320**	**312**	








Production Cost Planning Model Evaluation - 2019

Why Do We Need to Change Production Cost Models?

- Our current models, Prosym and System Optimizer, are no longer supported by ABB. Future resource planning will require more advanced production cost model features such as:
  - Climate Goals
    - CO2 tons cap with full hourly unit dispatch
  - Detailed ancillary services modeling
    - Prosym requires combining some ancillary services
  - Better optimized pumped storage and battery operation
    - Maximize the value of energy storage
  - Solar combined with battery storage
    - Solar provides all charging energy for the battery
  - Better handling of coal and natural gas fuel switching for the coal steam units
    - Model changes in capacity, O&M cost, heat rate, etc. using different fuels
  - Combined cycle multi-mode operation

Which Models Did We Evaluate?

- ABB introduced new models called **Capacity Expansion** and **Portfolio Optimization** in 2016
  - Duke started evaluation of the new ABB models in 2017 and continued through early 2019
  - Portfolio Optimization is too slow to solve the combined DEC and DEP system
  - Newest version still has issues modeling all required unit characteristics
  - User interface is not easy to use and documentation is lacking

- Two other models were selected to provide a comparison to the ABB models
  - **PLEXOS** by Energy Exemplar
  - **Encompass** by Anchor Power Solutions

- New models use Mixed Integer Linear Programming
  - Minimize production costs while satisfying constraints such as unit run times and ancillary service requirements
  - Flexible constraint logic set by user – solution optimality vs. model solve time
  - Generally better handling of limitations on energy, fuel, and emissions

What Scenarios Did We Run?

- **Capacity Expansion and Production Cost**
  - No CO_2 cost
  - CO_2 tax
  - CO_2 mass cap
  - Renewable portfolio standard
  - Retirement of existing units
  - Ancillary services

- **Production Cost Only**
  - Dual fuel option for coal units
  - Pumped storage and battery operation – detailed outputs
  - Ancillary services – detailed outputs
  - Avoided cost calculation (peak and off peak)

What Evaluation Criteria Did We Consider?

	Encompass	PLEXOS	ABB
Portfolio cost • Fuel cost, VOM, emission cost, dump and unserved energy cost	✓	✓	✓
Unit operation • Capacity factors, starts, storage charging and discharging, ancillary service contribution, dual fuel operation	✓	✓	✓
Model performance • Solve time and simplifications necessary to solve solution in a reasonable amount of time	✓	✓	✗
Ease of use • Data input and results output processes • Multi-user workflow	✓	✓	✗
Documentation • Process flow, inputs and outputs	✓	✓	✗

Which Model Did We Choose?

Encompass was selected as our new production cost and capacity expansion model

- Lower overall production costs than Prosym
  - Unit operations were similar between all models
  - Expansion plans minimized capacity reserve margin slightly better than PLEXOS
  - Encompass and PLEXOS are equally good at maximizing the value of pumped storage and batteries
- Slightly faster than PLEXOS in most scenarios
- User interface is easy to use
  - Data input and output are simple
  - Multiple users can edit data at the same time
  - Good documentation but help file needs to be expanded to include some newer features
- User base is limited and company is very small, leveraging other agreements
  - All Minnesota regulated electric utilities will use Encompass for future IRP filings

What Are the Next Steps?

- Anchor Power Solutions will create DEI, DEK and DEF databases from our existing model inputs
  - Only Carolinas database was created for the evaluation process
- Training for all planning group employees
- Benchmark Encompass results to current model runs
- Decision regarding use of Encompass for the 2020 IRP expected to be made by early June
- Expand model capabilities
  - Eastern Interconnect expansion plan
    - New plans based on scenarios such as CO_2 tax, high RPS requirements, climate goals
  - Zonal
    - Power prices for Duke regions
    - RTO studies
  - Nodal (Available 2021)
    - DC power flow/LMP
    - Transmission impacts of adding more solar

Appendix – How We Scored Each Model

- Scoring matrix based on a 1-5 scale with 5 being the highest
- Four categories – Capacity Expansion, Production Cost, Software Quality, Contract
  - Each category is broken down into several items
  - Models were given a score for each item
  - The importance of each scoring item was also weighted on a 1-5 scale
  - Total for each item is the score multiplied by the weight
- Encompass had the highest overall score followed closely by PLEXOS

Scoring Matrix

Capacity Expansion

	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Quality of Expansion Plan	5	5	5	5	25	25	25	PLEXOS plan has a slightly higher average reserve margin in CO2 Tax, but very small differences.
Total PVRR	4	5	4	3	12	15	12	ABB ignores ancillary services in capacity expansion runs. PLEXOS only uses nominal fixed charge rate. Encompass is more flexible.
Solution Time	5	5	5	4	20	20	20	Fast solutions from all models.
Unit Operation	4	5	5	4	16	20	20	Encompass and PLEXOS can model dual-fuel and solar/storage combo in capacity expansion runs. Encompass is the only model that incorporates start costs in capacity expansion runs.
Total - Capacity Expansion					73	80	77	

Production Cost

	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Total PVRR	3	5	5	5	15	25	25	Encompass and PLEXOS costs are very close.
Unit Operation	3	5	5	5	15	25	25	All models handle storage/solar combination and dual-fuel units. ABB was unable to model all unit operation constraints. PLEXOS allowed tight control of charging and discharging for the storage/solar combination. Encompass allowed tight control of charging but allowed total output of the combination to exceed the inverter limit in a few instances.
Solution Time	1	5	5	5	5	25	25	ABB performance is not competitive with the other models despite several years of development.
Total - Production Cost					35	75	75	

Scoring Matrix (cont)

Software Quality	ABB	Encompass	PLEXOS	Weight	ABB Total	Encompass Total	PLEXOS Total	Discussion
Ease of Use	1	5	5	5	5	25	25	ABB is difficult to learn for new users. Encompass uses familiary terminology to our current tools. PLEXOS terminology is different, but not too hard to learn.
Documentation	2	4	5	4	8	16	20	PLEXOS has an excellent help file system built into the interface. Encompass help is good, but has some missing features. ABB documentation is low quality.
Data Sharing	2	5	4	4	8	20	16	Easy to export Encompass inputs to spreadsheets for sharing with internal and external customers/stakeholders. PLEXOS inputs can be copied to Excel easily. ABB views can be exported to Excel, but only a few inputs at a time.
Multi-user Workflow	4	5	4	5	20	25	20	Encompass and ABB use a SQL Server database for a full multi-user environment. PLEXOS has a data management system that requires manual user coordination.
Auditing Data Changes	3	5	4	3	9	15	12	ABB requires all data changes to be viewed within the user interface while the other models can export inputs to spreadsheets or built-in comparison tools. Encompass shows the name of the user and the date of each data input change. PLEXOS and ABB do not provide any data change audit trail.
Exporting Results	1	5	5	5	5	25	25	Encompass is easy to export all results to Excel, but can't handle many years of hourly outputs. PLEXOS has a flexible data reporting tool, but can require multiple queries per run. Getting results out of ABB model is very slow, memory intensive and hasn't improved much in the last several versions. Efficient handling of hourly output will be essential in creating avoided energy costs for the Carolinas due to the multi-time-period rate design and the frequency of update.
Data Security	4	4	4	3	12	12	12	PLEXOS makes an automatic backup of the database when the file is opened. ABB and Encompass use SQL Server and would use database tools to recover from corruption.
Backup and Recovery	5	5	5	3	15	15	15	PLEXOS data is stored on file shares and are backed up each day. ABB and Encompass use a SQL Server database that is automatically backed up.
Scaling Up/Extending	4	4	5	3	12	12	15	Encompass and ABB can handle multiple user and concurrent runs. PLEXOS has an API that can be used to extend the capabilities of the model.
Total - Software Quality					94	165	160	
Total All Categories					**202**	**320**	**312**	

Attachment D

IRP Modeling Software Collaborative

Day 1

May 11, 2020

This collaborative will be recorded for internal use

Software Considerations/Evaluation Criteria (Page 1)
Models to be evaluated whether they have the functionality

Model Capabilities
1. Ability to optimize to emission limits
2. Capable of optimizing a broad range of retirement dates
3. Captures accurate long term costs of different lived alternatives
4. Accepts a non-linear escalation rate and negative escalation rates
5. Chronological model instead of using a load duration curve simplification for better renewable and storage modeling
6. Storage logic can handle more than once a day charging and discharging as well as long term storage modeling over weeks, seasons
7. Ability to tie storage charging to a specific technology
8. Ability to model ancillary service markets and assign benefits to specific technologies
9. Ability to accurately model economic reserve shutdowns (start-up cost, min down time, run time)
Model Transparency
10. Availability of manual to stakeholders (without a license preferred)
11. Provide transparency into modeling; access to software inputs, outputs (without a license preferred)
12. Licenses available at reasonable cost

Software Considerations/Evaluation Criteria (Page 2)
Models to be ranked against each other subjectively

Functionality
13. Ability to change the granularity (down to sub-hourly resolutions) and type of commitment logic depending on purpose of run (build plan generation or detailed dispatch)
14. Ability to run stochastics or other risk analysis on different types of runs including retirement analysis
15. Ability to coordinate the IRP modeling with the Distribution Operations long-term plan
16. Ability to optimize fuel blending
17. Specific storage technology properties such as degradation, storage level
18. Ability to design a simpler, more transparent, yet still robust approach to IRP modeling by reducing the number of software platforms
19. Market Price forecasting

Value and IRP process efficiency
20. Best value for the cost over entire lifecycle, for DTE and stakeholders
21. Intuitive interface making it easy to transition from current model
22. Dedicated software support
23. Reasonable model run time
24. Additional server not preferred
25. Large user base

Software Considerations/Evaluation Criteria (Page 3) Models to be ranked against each other subjectively

Nice to Have
26. Data visualization within the software
27. Straightforward error checking (messaging or other notification)
28. Program that may also work for other DTE modeling groups (e.g. Gen Ops)
29. Uncomplicated data import capabilities
30. Automatic reporting
31. Ability to track who makes the change to a database
32. Batch Running, ability to use macros and scripts
33. Easy exporting of input and outputs with no use of text files

Exhibit 2

Supporting Comment on PAYS Programs
James Owen, Renew Missouri Advocates

This supporting comment is offered by James Owen, on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association.

I have provided expert witness testimony before the Kentucky Public Service Commission in two prior rates cases, as well as expert witness testimony and IRP comments before regulators in Kansas and Missouri. Currently, I am the Executive Director of Renew Missouri Advocates and was the former ratepayer advocate for the State of Missouri. In this supporting comment, I explain the potential for PAYS Programs to help overcome barriers to participation in demand-side management programs and tap into cost-effective savings potential.

1. With current economic uncertainty as a real consideration for Kentuckians, demand-side resources are necessary to offset higher rates based on increasingly more expensive supply-side resources used for generation such as coal and gas. LG&E and KU's (collectively, the Companies) existing energy efficiency programs are inadequate for such consideration and the Companies should use their existing legal authority and access to capital to provide expanded energy efficiency programs. The planning and implementation of such programs will determine their success. Regardless of how this is done, the Companies should expand opportunities to achieve greater demand and other cost savings that benefit program participants as well as all ratepayers generally. Reaching all Kentuckians with demand-side

mechanism ("DSM") programs, regardless of income and energy consumption levels, can help the Companies achieve significant goals.

2. Energy efficiency is highly cost-effective and, when compared to traditional supply-side resources such as coal or natural gas, is the least-cost resource for electric utilities.[1] While the Companies focus on expensive fuel sources for generation in their proposed IRP, the least-cost resource (efficiency) is given scant attention.

3. According to the Companies' website,[2] "(c)urrently, 80 to 90 percent of our energy is produced using coal, nine to nineteen percent from natural gas and one percent from renewables. (The amount of coal and natural gas generation will ultimately depend on the relative price of coal and natural gas.) As the utility plan for the future, we continue our efforts to maintain a diverse generation portfolio and are continually evaluating potential energy supplies to determine which available sources would allow us to sufficiently provide safe, reliable, least-cost energy using commercially-available technologies."

4. Investing in energy efficiency as if it were a supply side resource will help LGE-KU reach their goal of offering safe, reliable, and least-cost energy to customers. Based on the Companies' current energy mix, energy efficiency is a more

[1] Cohn, C. 2021.The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-Funded Efficiency Programs in 2018. Washington, DC: ACEEE. Topic Brief. aceee.org/topic-brief/2021/06/cost-saving-electricity-largest-us-utilities-ratepayer-funded-efficiency

[2] https://lge-ku.com/environment/expanding-renewable-energy/expanding-our-renewables/expanding-our-renewables-help

effective investment per dollar than any investments in new coal, nuclear, or gas peaking plants will be. Additionally, with the high LCOE attributed to coal and natural gas plants in the market today, investments in energy efficiency to replace or retire existing generation will likely lead to immediate and long term energy savings for customers. Another way to think of this is that energy efficiency is more cost effective than 80-90% of the Companies' current portfolio and is a valuable resource that should be evaluated alongside future supply-side investments.

5. The Companies' energy efficiency programs are often inaccessible to the customers that need them the most. Renters, low-income households, and fixed-income customers face the highest barriers to participation. The Companies should expand their DSM programs with the goals of increased equity, access, participation, customer bill savings, and emission reductions. One key way to accomplish this would be to implement a PAYS® program, or a similar on-bill program, to maximize participation and customer energy savings[3].

6. PAYS®, or programs similar in nature, are employed by multiple utilities around the country, including rural electric cooperatives in Kentucky. Under the most recent data (February of 2020)[4] from the How$martKY™ program (a PAYS® program administered by the Mountain Association), the program assessed 607

[3] For a primer on how Pay As You Save ® works conceptually, the authors of this comment would direct the reader to this video: https://www.youtube.com/watch?v=nRoNSsaHJ8U

[4] https://www.seealliance.org/wp-content/uploads/SEEA_TOBGuide_FINAL_UPDATED_2020_04_13.pdf

buildings and offered improvements to 405 member-owners. Out of those, 320 retrofits were completed (a 79% offer acceptance rate) with an average investment of $7,743. These investments resulted in monthly savings of $51.98 against a $39.98 tariff charge resulting in a $12 monthly net cash flow. Those utilities have seen a 99.6% cost recovery rate, no disconnections for non-payment, and a negligible impact on rates.

7. Utilities have made over six-thousand PAYS® investments totaling $50 million in ten states across the country.[5] "Roanoke's PAYS® investments in efficiency upgrades generated an average heating peak load reduction of 1.3 kW/home, a cooling peak load reduction of 1.2kW/home, and an average per-home annualized reduction in energy consumption of 4,228 kWh."[6] The following table shows where PAYS® is currently being deployed:

---

[5] https://www.eeivt.com/status-reports/

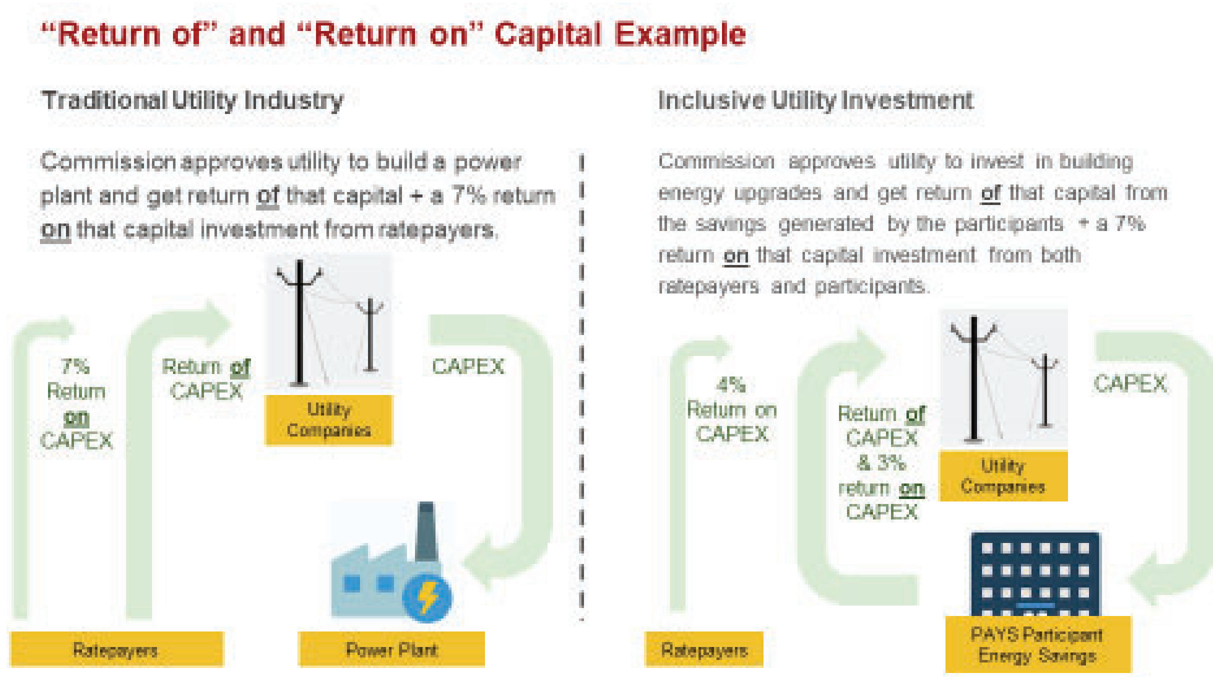
[6] Bickel, Stephen, Ferguson JG, and Kauffman, D. Utility Value of a Pay As You Save® Energy Efficiency Program. 2020. Proceedings of the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

State	Program	Utility	Website
Arkansas	HELP PAYS ®	Ouachita Electric	https://www.oecc.com/help
California	Windsor Efficiency PAYS ®	Town of Windsor Water Utility	https://www.townofwindsor.com/819/Windsor-Efficiency-PAYS
	EBMUD WaterSmart Pilot (now just called On-Bill Financing)	East Bay Municipal Utility District	https://www.ebmud.com/water/conservation-and-rebates/residential/bill-financing/
Kansas	How$mart™	Midwest Energy	https://www.mwenergy.com/environmental/energy-efficiency/howsmart
Kentucky	How$mart KY	Big Sandy RECC	http://www.howsmartky.com/
		Grayson Electric Co-op	http://www.howsmartky.com/
		Fleming-Mason Energy	http://www.howsmartky.com/
		Jackson Energy Co-op	http://www.howsmartky.com/
Missouri	Pay As You Save ®	Ameren, Ameren Gas	https://www.amerenmissourisavings.com/pays
	Pay As You Save ®	Evergy	https://www.evergy.com/ways-to-save/programs-link/research-and-pilot-program/pays
		Spire	*Approved by the PSC*
		Liberty/Empire	*Approved by the PSC* https://psc.mo.gov/Electric/PSC_Approves_Agreement_In_Liberty_Cycle_1_MEEIA_Plan--pr-22-91
New Hampshire	Smart Start	Eversource	https://nhsaves.com/municipal-smart-start-program/
		New Hampshire Electric Co-op	https://www.nhec.com/smartstart-project-financing/
North Carolina	Upgrade to $ave	Roanoke Electric	https://www.roanokeelectric.com/UpgradeToSave
Tennessee	U-Save Advantage	Appalachian Electric Co-op	http://aecoop.cms.coopwebbuilder2.com

8. By implementing a PAYS® or similar on-bill tariff program with robust consumer protections, and treating it as an energy resource, the Companies can reduce the energy burden faced by their customers while increasing revenue through the operation of the program. This would be a win-win-win for the utility, customers, and the communities served. PAYS® Programs have a proven record of accomplishment in vertically integrated utilities around the country and are currently being offered by every investor-owned utility in the state of Missouri. The Companies can build on the lessons learned in Kentucky and neighboring states to benefit their customers.

9. Some stakeholders object to PAYS® programs on the grounds that they are simply loans or financing programs, which utilities state do not fit into their

business model. However, PAYS® programs should instead be understood as capital investments made by the utility. Just as utilities make investments in power plants, transmission lines, and distribution wires, they can also make investments in energy efficiency improvements in their customer's homes. Utilities already have a commercial relationship with the occupants of virtually every building in their service territories – that is a supplier to a customers' demand. PAYS® makes it financially possible and attractive for utilities to capitalize home energy upgrades to create utility-wide benefits in lieu of investments in generation capacity. This program harnesses expansive access to low-cost capital for such investments with terms determined to be just, reasonable, and fair by their regulators. The graphic below illustrates how inclusive investments via a PAYS program can offer utilities a return on their investment while improving their customer's buildings and reducing their energy costs.



10. Investments in a PAYS® program – or something similarly composed – will increase the utilities' ability to meet their customers' electricity needs safely, reliably, and at the lowest cost while easing burdens on low-income customers.

Respectfully submitted,

James Owen
Executive Director of Renew Missouri Advocates, Inc.