Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_1 Please provide all Kentucky Power responses to data requests from all other parties in this proceeding.

RESPONSE

Kentucky Power objects to this request. Kentucky Power on March 13, 2023, filed its notice of election to use electronic filing procedures pursuant to 807 KAR 5:001, Section 8. On June 5, 2023, Joint Intervenors filed their written statement that they possessed the facilities to receive electronic transmissions pursuant to 807 KAR 5:001, Section 8(9). Prior to June 5, 2023, Joint Intervenors did not object to the use of electronic filing procedures and the service of all papers by electronic means pursuant to 807 KAR 5:001, Section 8(9)(a). Further, 807 KAR 5:001, Section 8(8)(b) provides that in proceedings governed by the Commission's electronic filing procedures "each party shall be solely responsible for accessing the Commission's website at http://psc.ky.gov to view or download the submission." As such, Joint Intervenors may view or download the requested information from the Commission's website.

Witness: Counsel

DATA REQUEST

JI 1_2 Please provide any redacted documents included in this filing in non-redacted, electronic versions (machine readable, unprotected, with formulas intact), if they have not already been provided to the Joint Movants.

RESPONSE

Joint Intervenors provided an executed non-disclosure agreement to the Company on May 22, 2023, and on that same date, the Company provided counsel for Joint Intervenors via email with all of the confidential, unredacted pages of the Company's IRP Report. The Company has no additional documents responsive to this request.

Witness: Counsel

DATA REQUEST

JI 1_3 Please refer to the IRP at page 87 of 1182, footnote 15, stating: "The smaller single shaft NGCC block size can also be considered as a proxy for a partial ownership option for a larger multi-shaft NGCC where Kentucky Power would coordinate the addition of this resource with other parties."

a. Did the Company also evaluate partial ownership of the H-class turbine single shaft configuration with 418 MW capacity? If not, please explain why not.

b. Did the Company evaluate partial ownership of resource options other than the larger multi-shaft NGCC mentioned in the above- referenced statement?

i. If so, please explain how partial ownership of each resource option was evaluated in this IRP, provide supporting workpapers in native file format with formulas intact, and describe conclusions drawn from that evaluation.

ii. If not, please explain why not.

RESPONSE

a) The Company did not evaluate a partial ownership of single shaft CC configuration. The Company modeled two different size configurations for CCs as a proxy for this kind of resource.

b) The Company did not model a resource where partial ownership was assumed. For the purpose of this IRP, partial ownership was not considered as the Company included a wide array of resource alternatives that included a range of size and cost differences to evaluate different resources.

Witness: Gregory J. Soller

Witness: Thomas Haratym

DATA REQUEST

JI 1_4 Please refer to the IRP, Section 5.7, addressing "Short-Term Market Purchase" alternative resources and answer the following requests:
a. Please provide the workpaper(s) underlying Figure 35, titled "PJM Capacity Price Outlook", in native file format with formulas intact.
b. Please identify and describe the source for the Company's forecasted price levels in the PJM Reliability Pricing Mechanism.
c. At page 110 of 1182, the IRP explains that the short-term market purchase "resource is assumed to have no energy associated with it and a contract term of one year." Is the Company assuming a short-term market purchase of capacity would be accomplished through a bilateral contract, through the RPM, or some other means? Please explain in full.
d. At page 111 of 1182, the IRP explains that the short-term market purchase "resource is available in the model through 2025 and in 2028 up to 500 MW per year, and in 2026, 2027, 2030, 2031, 2033, 2034, 2036, and 2037 up to 235 MW per year."
i. Please confirm that the short-term market purchase resource was not available to be selected in the model in each of the following years: 2029, 2032, and 2035. If anything but confirmed, please explain in full.
ii. If subpart (i) is confirmed, please explain in full the Company's reason for making the short-term market purchase resource unavailable in certain years.
iii. Please explain in full the Company's reasons for limiting short- term market purchases to 500 MW through 2025 and in 2028.
iv. Please explain in full the Company's reasons for limiting short- term market purchases to 235 MW per year in 2026, 2027, 2030, 2031, 2033, 2034, 2036, and 2037.

RESPONSE

a) Please see response for KPSC_1_13.

b) Please see response for KPSC_1_13.

c) The Company assumed it would purchase a capacity contract with 1 year term. This would be conducted through an RFP process.

d-i) Confirmed.

d-ii) The Company made short-term market purchases available in specific years to limit the model from selecting this resource as a long-term option. If this resource was made available in all years, the Company anticipated that the model might select this instead of firm resources to meet its obligations over the long-term.

d-iii) The Company's Going In position identified a need in 2028 of nearly 500 MW that it was not confident it could meet by procuring long-term resources. The Company made this resource available in this amount to provide the model adequate resource alternatives to meet its obligations.

d-iv) The Company identified 235MW as a limit to allow for the model to adequately analyze the opportunity to rely on this resource in place of a CT if it was economic.

Witness: Gregory J. Soller

Witness: Thomas Haratym

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DATA REQUEST

JI 1_5 Please refer to the IRP, at page 17 of 1182, stating that "[i]n total, the Kentucky Power portfolio is expected to reduce emissions by 90% by 2037 relative to the 2005 baseline." Please confirm that this statement refers to direct carbon dioxide emission reductions. If not confirmed, please describe in detail each air emission included in the referenced statement.

RESPONSE

Confirmed

Witness: Gregory J. Soller

Witness: Thomas Haratym

DATA REQUEST

JI 1_6 Please refer to the IRP, Section 7.2.4.2, at page 151 of 1182, stating that the "Local Impacts and Sustainability" objective "allows Kentucky Power to evaluate the relative exposure of resource portfolios under outcomes where significant reductions in GHG emissions are required in the power sector – a plausible outcome with potentially material impacts on the cost to serve Kentucky Power's customers."

a. Has Kentucky Power attempted to estimate the direct methane emissions of its existing portfolio, or any resource portfolio options presented in the IRP? If so, please produce each such estimate. If not, please explain in full why not.

b. Has Kentucky Power attempted to estimate the direct nitrous oxide emissions of its existing portfolio, or any resource portfolio options presented in the IRP? If so, please produce each such estimate. If not, please explain in full why not.

c. Has Kentucky Power attempted to estimate the direct greenhouse gas emissions of its existing portfolio, or any resource portfolio options presented in the IRP using a carbon dioxide equivalent metric? If so, please produce each such estimate. If not, please explain in full why not.

RESPONSE

a) Direct methane emissions were not modeled in this IRP. Future policies that may potentially impose regulatory limitations on methane emissions are uncertain at this time and therefore were not considered in the IRP modeling.

b) Please see KPCO_R_KPSC_1_8_ConfidentialAttachment10, Emissions and Energy worksheet for NOx Emissions estimates.

c) Please see KPCO_R_KPSC_1_8_ConfidentialAttachment10, Emissions and Energy worksheet for direct CO2 emissions estimates. A Carbon Dioxide equivalent metric was not estimated for the purposes of this IRP since the analysis was only providing directional insight to the potential changes in Greenhouse Gas emissions for different portfolios.

Witness: Thomas Haratym

DATA REQUEST

JI 1_7 The IRP assumes the Company's portfolio will not include the Mitchell units in 2028. (E.g., Vol. A at 14 ("This going-in position reveals a need for new capacity in 2028, reflecting the divestiture of Kentucky Power's stake in Mitchell coal plant."); id. at 26 of 1182 ("A key assumption in the 2019 Preferred Plan that is not included in the current IRP was the continued stake in the Mitchell coal plant (780 MW), which is now divested in 2028."); id. at 55 of 1182 ("The capacity associated with Kentucky Power's share of the Mitchell Plant will cease after the 2027/2028 PJM Planning Year.")). As part of the Company's three-year action plan (summarized in the IRP's Executive Summary at page 18), do you anticipate filing an application pursuant to SB 4 (2023) seeking approval from the Commission for the retirement of a fossil fuel-fired generating unit? If not, please explain why not.

RESPONSE

The Company does not anticipate filing an application for approval under SB4 for the retirement of a fossil-fueled generating unit because, among other reasons, the Mitchell Plant is not being retired per the definitions and/or provisions of SB 4, and because the Commission issued its order regarding Mitchell in Case No. 2021-00004 prior to SB4's enactment.

The only fossil-fueled generating unit in the Company's resource portfolio (post-2028) is Big Sandy Plant, which is a gas-fired unit (Unit 1). The IRP Preferred Plan contemplates a life extension for Big Sandy Unit 1 from 2031 to 2041.

Witness: Brian K. West

DATA REQUEST

JI 1_8 Please refer to the IRP, Section 7.2.4.2, at page 152 of 1182, stating that "[c]arbon emissions are defined as the direct emissions from Kentucky Power's owned and contracted generating resources." Has Kentucky Power attempted to estimate its indirect carbon emissions? If so, please produce each such estimate. If not, please explain why not.

RESPONSE

The IRP does not include assumptions for indirect carbon emissions. Therefore, indirect carbon emissions are not a differentiator among resources evaluated in the model.

Witness: Thomas Haratym

DATA REQUEST

JI 1_9 For each monthly billing period in calendar years 2021 and 2022, as well as the first quarter of 2023, please provide the following information for residential customers (under the Residential Service tariff):
a. Service charge (per month);
b. Energy charge (per kWh);
c. FAC factor (per kWh);
d. Actual average monthly usage (kWh).

RESPONSE

The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence, and because the requested information is equally available to Joint Intervenors in the Company's tariffs that are presently on file with the Commission and via other information publicly available on the Commission's website. Notwithstanding these objections, see the below table for the residential average monthly usage (kWh) for January 2021 through March 2023.

Year	Month	Avg Billed Residential kWh
2023	January	1,812
2023	February	1,434
2023	March	1,145
2022	January	1,657
2022	February	1,887
2022	March	1,378
2022	April	1,103
2022	May	881
2022	June	1,008
2022	July	1,207
2022	August	1,218
2022	September	1,092
2022	October	889
2022	November	949
2022	December	1,482
2021	January	1,920
2021	February	1,845
2021	March	1,519
2021	April	1,043
2021	May	895
2021	June	969
2021	July	1,185
2021	August	1,216
2021	September	1,192
2021	October	888
2021	November	952
2021	December	1,502

Witness: Brian K. West

DATA REQUEST

JI 1_10 Please refer to Figures 67 and 68 of the IRP, Volume A, and answer the following requests.

a. Please confirm that the performance indicator "% of Income", reflecting the metric "Percentage of wallet for residential customers," was not included in the final IRP Scorecard.

i. If confirmed, please explain why the % of income performance indicator was eliminated.

ii. If not confirmed, please explain in full.

b. Please describe the data and calculations that would have been used to quantify the "percentage of wallet for residential customers" impact for each portfolio.

c. Did the Company determine, preliminarily or otherwise, for any portfolio considered in the IRP, the "percentage of wallet for residential customers"? If so, please explain and provide the results of each such analysis, including production of workpapers in native file format with formulas intact.

RESPONSE

a-i and ii.) The performance indicator "% of Income" was included in Figure 67. It was not included in the Final IRP scorecard. It was intended not to be included in either. Its inclusion in Figure 67 was in error. As it was not considered in the Final IRP scorecard this metric was not included in the IRP analysis.

b) The requested calculations have not been performed for purposes of this IRP.

c) No. The requested analysis has not been performed. However, the Company did estimate the bill impacts and rate impacts of the Preferred Plan, these analyses are discussed in Section 7.5.3 and 7.5.4 of the IRP.

Witness: Thomas Haratym

DATA REQUEST

JI 1_11 Please refer to the IRP, Volume A, Section 7.5.3, summarizing the "Estimated Bill Impacts of the Preferred Plan" and answer the following requests:
a. Please produce the workpaper(s) underlying Figure 83, presented at page 180 of 1182.
b. Please provide the monthly bill impact for the Reference portfolio. c. At page 179 of 1182, the IRP states that "the monthly bill for all portfolios increased," and continues to compare the increased bill impact between the Reference portfolio and the Preferred Plan. Please provide the monthly bill impact for each portfolio evaluated as part of the IRP.

RESPONSE

a) Please see KPCO_R_KPSC_1_8_Attachment3.

b) The Monthly Bill impact was specifically analyzed for only the Reference and Preferred Portfolios. This analysis can be found in KPCO_R_KPSC_1_8_Attachment3. The additional requested analysis for the other portfolios has not been performed. The bill impact only reflects the asset changes within the reference and preferred plan, and there could be other bill impacts from other investments the company makes.

Witness: Gregory J. Soller

DATA REQUEST

JI 1_12 Please refer to the IRP, Volume A, at pages 14–15 of 1182. The number of megawatts of New Wind and New Solar depicted in Figure ES–2 appear to differ from the numbers stated on p. 15 ("800 MW of new solar and 700 MW of new wind"). Please explain the discrepancy.

RESPONSE

Figure ES-2 illustrates the accredited capacity of the solar and wind resources. The reference to 800MW of new solar and 700MW of new wind is referring to the Nameplate capacity of these resources.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_13 Please refer to the IRP, Volume A, at page 16 of 1182, which states, "It should be noted that growth for the commercial class is fueled by a large customer addition."

a. Please identify the large customer addition (including the nature of the customer's business, the customer's location, and the anticipated timing of the addition), and the energy demand associated with that large customer addition.

b. Has the Company modeled the load forecast without that large customer addition?

RESPONSE

a. Ebon is the large customer load added to the Company's commercial energy forecast. It will be located in Louisa, Kentucky and it is a blockchain data computing complex customer. See KPCO_R_JI_1_13_ConfidentialAttachment1 for demand for this large customer addition.

b. Yes. Ebon's projected load was included as an add-factor, as it was considered as extraordinary growth and not captured by the commercial energy model.

Witness: Glenn R. Newman

Kentucky Power Company
Commercial Large Customer Addition

Load Addition in 2023	[redacted]
Load Addition in 2024 and Beyond	

DATA REQUEST

JI 1_14 Please refer to the IRP, Volume A, at page 24 of 1182, which states "Pending an assumed completion of a transfer of Kentucky Power from AEP to Liberty Power, the Company will participate as a member of the Power Coordination Bridge Agreement (PCBA) through the 2023/2024 PJM Planning year. The Company will then look to source bilateral capacity agreements as needed to support any capacity needs not fulfilled by its own firm resources."

a. Does the Company still plan to participate in the PCBA through the 2023/2024 PJM Planning year? Please explain why or why not.

b. Does the Company still plan to source bilateral capacity agreements for the years following the 2023/2024 PJM Planning Year? Please explain why or why not.

RESPONSE

a. and b. See the Company's response to AG-KIUC 1_6.

Witness: Brian K. West

DATA REQUEST

JI 1_15 Regarding the "assumed completion of a transfer of Kentucky Power from AEP to Liberty Power," IRP, Volume A, page 24 of 1182, the Company has subsequently announced that the planned sale has been cancelled.[1]

a. Please confirm that the Company still plans to seek securitization of retired coal assets, as stated in the news release. If yes, please identify by what means the Company plans to seek securitization, which retired coal assets the Company intends to seek to securitize, and the anticipated timeframe for that request.

b. Does the Company plan to securitize retired coal assets change any of the modeling assumptions or modeling results for the IRP? Please explain why or why not and please provide any related data, documentation, or analysis.

c. With regard to the Company's stated intent to focus on economic development in the region, has the Company identified any specific businesses, projects, or programs as targets for its economic development efforts? If yes, please explain in detail. If not, please explain why not.

d. The Company's press statement says that the Company "believes that leveraging Kentucky's manufacturing talent will help attract onshoring and reshoring which, combined with access to lower cost power, will strengthen the regional economy and attract new investment."

i. Please explain the phrase "access to lower cost power." Lower cost power relative to whom or what?

ii. Please identify any specific industries or businesses that the Company intends to target for "onshoring and reshoring." If there are none currently, please explain why not.

e. Does the Company intend to offer discounted electric rates to industrial customers through special contracts and/or its Tariff E.D.R.? If yes, please explain in detail. If not, please explain why not. f. Does the Company intend to seek any changes to its Tariff E.D.R.? If yes, please explain in detail. If not, please explain why not.

[1] See American Electric Power, News Release: AEP Outlines Strategic Focus on Kentucky (Apr. 17, 2023), https://www.aep.com/news/releases/read/8905/AEP-Outlines-Strategic-Focus-On- Kentucky.

RESPONSE

a. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of evidence. Notwithstanding these objections, confirmed. The Company plans to seek securitization of the Big Sandy Decommissioning regulatory asset as a part of its base rate case filing to be filed at the end of June 2023.

b. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, no, it does not change any of the modeling results in the IRP. Retired coal assets do not produce capacity or energy.

c. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, the Company is constantly focused on all types of economic development projects and opportunities that will help its customers in eastern Kentucky.

Regarding targeted efforts, in 2017 Kentucky Power assisted its partners, Ashland Alliance, One East Kentucky and Eastern Kentucky Concentrated Employment (EKCEP) in a study of the region's workforce. That study reported the skills of displaced coal miners and steel workers transfer well to the aerospace/aviation, automotive and advanced manufacturing sectors. Ashland Alliance and One East Kentucky used the workforce data and lead generation consultants (paid for with KPEGG awards) to identify companies in those sectors with active expansion or relocation projects. Kentucky Power has assisted Ashland Alliance and One East Kentucky with targeted recruitment meetings with companies in those sectors. Furthermore, with the current increase in projects available in the electric vehicle supply chain and solar components, Kentucky Power and its partners are actively targeting those sectors as well.

d. i. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, lower cost power means power that is less costly than in other regions of the country.

d. ii. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, see the Company's response to part c.

e. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, Tariff E.D.R. is available to customers who meet the specific requirements of the tariff. If a potential customer requires special contract terms that are not currently covered by the Company's existing tariffs, a special contract may be offered. Special contracts as well as contracts under Tariff E.D.R. are subject to Commission approval.

f. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence.

Witness: Brian K. West

DATA REQUEST

JI 1_16 Please refer to the IRP, Vol. A, at page 39 of 1182, which states, "Commercial usage is buoyed by large customer additions in the near term and sees average annual growth of 4.0% over the 2021-2030." Please explain the basis for this statement. If Kentucky Power has identified any specific expected large customer additions, please identify them and their anticipated size, location, energy consumption, and type.

RESPONSE

Please see the response to JI 1_13 and JI 1_18.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_17 Does Kentucky Power Company consider cryptocurrency facilities to be commercial or industrial customers? Please explain your answer.

RESPONSE

For the purposes of this IRP, the Company classifies cryptocurrency facilities as commercial load based on their NAICS (North American Industry Classification System) code.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_18 With respect to the cryptocurrency facilities in Kentucky Power territory:
a. Please identify all currently operating cryptocurrency facilities in Kentucky Power territory by name, location, capacity need (in MW), percentage of capacity need that is firm capacity, and anticipated load factor.
b. Please identify all proposed cryptocurrency facility that the Company anticipates will begin operating in its territory in the next three years by name, location, capacity need (in MW), percentage of capacity need that is firm capacity, and anticipated load factor.
c. For each currently operating or proposed cryptocurrency facility identified in response to paragraphs (a) and (b), please explain in detail whether or how the Company has incorporated the facility into its load forecast for this IRP.

RESPONSE

a. and b. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, please see KPCO_R_JI_1_18_ConfidentialAttachment1 for the requested information.

c. The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, please see KPCO_R_JI_1_18_ConfidentialAttachment2 provides the requested information.

Witness: Glenn R. Newman

Kentucky Power Company
New and Existing Cryptocurrency-Related Customers

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Customer Name	Capacity	Firm Capacity	Estimated Load Factor
Existing Customers			
Cyber Innovation Group LLC	20 MW	1 MW	80-90%
Cyber Innovation Group LLC	7 MW	0 MW	80-90%
Discover AI LLC	15 MW	1 MW	80-90%
Propoosed Customers			
A	[redacted]		
Ebon	250 MW	25 MW	80-90%

Kentucky Power Company
New and Existing Cryptocurrency-Related Customers

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Customer Name	Included in IRP Load Forecast	MW Included
Existing Customers		
Cyber Innovation Group LLC	No	0
Cyber Innovation Group LLC	No	0
Discover AI LLC	No	0
Propoosed Customers		
A	No	[redacted]
Ebon	Yes	

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JI 1_19 Please refer to the IRP, Volume A, at page 52 of 1182, which states, "Since 2016, the Company's economic development team has identified 22 projects that could play a significant role in either a new firm entering the local economy or an existing firm expanding its operations."
a. Please provide the list of 22 projects identified by the Company's economic development team since 2016, and please identify the economic sectors to which they belong.
b. Are any of those projects currently under way? If so, please identify them.
c. Please identify any assumptions and inputs into the Company's IMPLAN model as described on p. 52.

RESPONSE

a. See KPSC_R_JI_1_19_ConfidentialAttachment1 for the requested information.

b. All of the projects are operational with the exception of two projects that are no longer operating.

c. Employment data provided in KPSC_R_JI_1_19_ConfidentialAttachment1 was used as an input into the IMPLAN model. The impacts of each project were developed using industry specific characteristics. The industries that are initially affected are determined by the Company's NAICS code.

Witness: Glenn R. Newman

Witness: Brian K. West

Kentucky Power Company
Economic Development Projects Evaluated for the IRP

Project Name	NAICS Code	NAICS Title	Direct Jobs	Direct Monthly kWh
[redacted]	325199	Manufacturing	[redacted]	[redacted]
[redacted]	325998	Manufacturing	[redacted]	[redacted]
[redacted]	336120	Manufacturing	[redacted]	[redacted]
[redacted]	331110	Manufacturing	[redacted]	[redacted]
[redacted]	611310	Educational Services	[redacted]	[redacted]
[redacted]	212111	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
[redacted]	212111	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
2017 - McCoy Elkhorn Coal LLC	212111	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
[redacted]	212111	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
[redacted]	332311	Manufacturing	[redacted]	[redacted]
[redacted]	212111	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
[redacted]	481190	Transportation and Warehousing	[redacted]	[redacted]
[redacted]	923110	Public Administration	[redacted]	[redacted]
[redacted]	493110	Transportation and Warehousing	[redacted]	[redacted]
[redacted]	621111	Health Care and Social Assistance	[redacted]	[redacted]
2019 - Big Run Landfill	562998	Administrative and Support and Waste Management	[redacted]	[redacted]
2019 - Dajcor Aluminum (Project Core)	331318	Manufacturing	[redacted]	[redacted]
[redacted]	518210	Data Processing, Hosting, and Related Services	[redacted]	[redacted]
[redacted]	213112	Mining Quarrying and Oil and Gas Extraction	[redacted]	[redacted]
2020 - Air Products - Ashland Plant Retention	325120	Industrial Gas Manufacturing	[redacted]	[redacted]
[redacted]	423510	Metal Service Centers and Other Metal Merchant Wholesalers	[redacted]	[redacted]
[redacted]	332420	Metal Tank (Heavy Gauge) Manufacturing	[redacted]	[redacted]

DATA REQUEST

JI 1_20 Please refer to the IRP, Volume A, at page 58 of 1182, which states, "A FIP that further revises the ozone season NOx budgets under the existing CSAPR program in those states, including Kentucky, is expected to be finalized in spring of 2023 and will likely take effect for the 2023 ozone season. Management is evaluating the impact of changes in the rule." EPA announced that it has finalized this FIP on March 15, 2023.[2]

a. Please provide any analysis of the impacts of this FIP as finalized on March 15, 2023, on Kentucky Power's existing supply-side generating resources.

b. Does Kentucky Power's IRP modeling account for the costs of purchasing annual and ozone season NOx allowances for fossil fuel- fired generators for both current and future fossil fuel-fired resources? If yes, please provide the cost assumptions used by Kentucky Power in its modeling. If no, please explain why not.

c. Does the final FIP change the cost assumptions used by Kentucky Power? Please explain why or why not. If so, please explain how the cost estimates will change.

d. Does the Company anticipate additional (i.e., not currently in use) pollution control measures or equipment will need to be utlized to comply with this rule? Please explain your answer.

e. If so, does the Company have estimates regarding cost of compliance? Do those differ from estimates and assumptions already incorporated in the IRP model? Please explain your answer.

f. Does the Company anticipate needing to purchase additional allowances through the open market beyond what it will be allocated for Big Sandy and its shares of Mitchell? Please explain your answer.

g. Please provide the monthly historical number of annual and ozone season NOx allowances used, purchased, and sold by Kentucky Power and the associated purchase cost for the 2017–2022 period.

[2] EPA, EPA Announces Final "Good Neighbor" Plan to Cut Harmful Smog, Protecting Health of Millions from Power Plant, Industrial Air Pollution (last updated Mar. 15, 2023), https://www.epa.gov/newsreleases/epa-announces-final-good-neighbor-plan-cut-harmful- smog-protecting-health-millions.

RESPONSE

a. Based on allocation information provided in the FIP, the rule does not appear to restrict Kentucky Power generating asset availability based on projected economic dispatch of the units.

b. Cost allowances were not specifically modeled in this IRP however, the Company modeling included a NOx cost for emissions as shown in KPCO_R_JI_1_20_Attachment2.

c. Please refer to the response to subsection (b). The IRP includes assumptions based on information available at the time of the modeling. The Company has not performed the analysis requested.

d. No, Kentucky Power does not anticipate that additional pollution control measures or equipment will be needed due to current emissions controls, good maintenance and operating practices and regular performance evaluations of its existing units, and anticipated capacity factors.

e. N/A.

f. Please refer to subpart (b). The Company has not performed the analysis requested.

g. Please see KPCO_R_JI_1_20_Attachmment1 for the requested information.

Witness: Gary O. Spitznogle

Witness: Thomas Haratym

DATA REQUEST

JI 1_21 Please refer to the IRP, Volume A, at page 58 of 1182. Please provide the following information related to SO2 emissions allowances:
a. Does the Company's IRP modeling include costs for purchasing SO2 emissions allowances for both current and future fossil fuel- resources? Please explain why or why not.
b. Please provide any cost estimates for SO2 emissions allowances relied on by the Company in its IRP modeling.
c. Please provide the monthly historical number of SO2 emissions allowances used, purchased, and sold by Kentucky Power and the associated purchase cost in the 2017-2022 period.

RESPONSE

a & b. The Company modeled an SO_2 cost for emissions as shown in KPCO_R_JI_1_21_Attachment1.

c. The Company does not compile data in the requested fashion.

Witness: Gary O. Spitznogle

Witness: Thomas Haratym

DATA REQUEST

JI 1_22 For the new gas combustion turbine in the IRP preferred portfolio:
a. Please confirm that the gas CT selected in the preferred portfolio is not modeled with carbon capture and sequestration and/or hydrogen cofiring.
b. Has Kentucky Power developed estimates of the costs of those co-firing with hydrogen and carbon capture and sequestration (including capital and operating costs) over the 15-year IRP study period? If so, please provide those cost estimates and any data or analysis supporting those estimates.
c. Is the new gas CT selected by the Company's preferred portfolio expected to be a low load, intermediate load, or baseload unit?
d. Is the gas CT in the preferred portfolio capable of meeting the Clean Air Act 111(b) New Source Performance Standards as proposed by EPA? (3 EPA, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, (last updated May 15, 2023), https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards- and-guidelines-fossil-fuel-fired-power)
e. Does the capacity of the new gas CT in the preferred portfolio account for the heat rate and capacity penalties associated with CCS?

RESPONSE

a. Confirmed, the gas CT selected in the preferred portfolio is not modeled with carbon capture and sequestration and/or hydrogen cofiring in this IRP. However, the CT modeled is assumed to be capable of cofiring with hydrogen as discussed in section 5.5.3. of the IRP.

b. The Company did not develop estimates for a co-fired CT with hydrogen and carbon capture and sequestration. Section 5.5.3 of the IRP provides further details on the modeling assumptions associated with retrofitting NGCT units to burn hydrogen exclusively.

c. The Company did not classify new gas CT as low load, intermediate load or baseload units. The modeling resulted in the CT unit operating at an average long-term capacity factor around 30%.

d. The Company objects to this request to the extent it calls for a legal conclusion or legal analysis. Without waiting these objections, the Company states that the rules referenced in the question are not yet final and any analysis based on them would be speculative and premature. In addition, the IRP is for planning purposes and any generation facilities eventually constructed would be constructed in compliance with applicable laws and regulations.

e. No.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_23 Regarding the Big Sandy life extension modeled in the IRP:
a. Does the Big Sandy extension supply-side resource in the IRP preferred plan include an assumption that the unit will be retrofitted with carbon capture and sequestration or co-fire with hydrogen? Why or why not?
b. In the preferred portfolio, is Big Sandy expected to operate with greater than 50% capacity factor?
c. Is the Big Sandy extension in the Company's preferred portfolio capable of meeting the Clean Air Act 111(d) performance standards for greenhouse gas emissions as proposed by EPA?4 Id.

RESPONSE

a. No, for purposes of the IRP the Big Sandy Unit 1 supply-side resource was modeled for the continued operation for 10 additional years in its current configuration.

b. No, the capacity factor was less than 50% as modeled in the IRP.

c. The Company objects to this request to the extent it calls for a legal conclusion or legal analysis. Without waiving this objection, please see the Company's response to JI 1_22(d).

Witness: Gary O. Spitznogle

Witness: Thomas Haratym

DATA REQUEST

JI 1_24 Please refer to the IRP, Vol. A, page 112 of 1182, which states that "an analysis to undertake a study to determine if there are customer benefits to be gained from leaving PJM or other options is anticipated following a presumed completed transaction for Kentucky Power to Liberty." Does Kentucky Power still plan to conduct an analysis regarding "customer benefits to be gained from leaving PJM or other options"? If so, on what timeline? If not, please explain why not.

RESPONSE

This was a commitment by Liberty as a part of the potential sale to Liberty which has now been terminated. The Company considers its membership in PJM and participation in AEP's FRR plan to provide significant benefits to customers.

Witness: Brian K. West

DATA REQUEST

JI 1_25 For the Short-Term Market Purchases of capacity selected by the preferred portfolio, how does Kentucky Power plan to procure that capacity? Will the Company issue an all-source request for proposals? Please explain your answer.

RESPONSE

Please see IRP Section 8.2 on page 181. For purposes of the IRP, it is assumed that the Company has access to capacity markets to satisfy its PJM capacity obligations. The Company has not yet made a final decision as to how the referenced capacity will be procured.

Witness: Brian K. West

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DATA REQUEST

JI 1_26 Did the Company model the impact of the Energy Community Tax Credit Bonus[5] for projects, facilities, and technologies located in energy communities inside the Kentucky Power service territory and elsewhere?
a. Has Kentucky Power done any mapping or spatial analysis of areas within its service territory that qualify for the Energy Community Tax Credit Bonus?
i. If so, please provide any such maps or analysis.
ii. If not, please explain why not.

[5] U.S. Dep't of Energy ("DOE"), Energy Community Tax Credit Bonus https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d (last visited May 22, 2023).

RESPONSE

The Company did not perform any mapping or spatial analysis of areas within its service territory that might qualify for the Energy Community Tax Credit Bonus. The IRP model does not include an assumption regarding an impact for Energy Community Tax because for purposes of the IRP the Company did not model any location-specific resource other than the Big Sandy Unit 1 operation extension alternative.

Witness: Gregory J. Soller

Witness: Thomas Haratym

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DATA REQUEST

JI 1_27 Did the Company's IRP Modeling consider the availability of low-interest loans for reducing emissions from existing fossil fuel infrastructure through the DOE Energy Infrastructure Reinvestment (EIR) program[6]?
a. If so, what was the cost impact of utilizing the DOE EIR program for this purpose? Please provide any relevant data or analysis.
b. If not, please explain why not.

[6] DOE, *ENERGY INFRASTRUCTURE REINVESTMENT (EIR) PROGRAM (SECTION 1706)* https://www.energy.gov/lpo/inflation-reduction-act-2022(last visited May 22, 2023).

RESPONSE

For this IRP, the Company assumed a consistent discount rate in all of its analysis.

a. See the Company's above response.

b. The qualification for these loan programs are not guaranteed and therefore were not modeled within this IRP.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_28 Did the Company's IRP process consider the availability of the Low-Income Communities Bonus Credit Program for solar and wind facilities in low-income communities or developed as part of a qualified low-income residential building project or economic benefit project.[7]

[7] *See e.g.*, Internal Revenue Service Notice 2023-17, *Initial Guidance Establishing Program to Allocate Environmental Justice Solar and Wind Capacity Limitation Under Section 48(e)* (Feb. 13, 2023), https://www.irs.gov/pub/irs-drop/n-23-17.pdf.

RESPONSE

For this IRP, the Company did not model any location-specific resource other than the Big Sandy Unit 1 operation extension alternative. This includes not modeling anything specific to the referenced IRS publication.

Witness: Thomas Haratym

DATA REQUEST

JI 1_29 In reference to the Market Potential Study on page 64 of 1182 of the IRP, please answer the following requests:
a. When was the study initiated?
b. What is the timeline for completion of the study?
c. Will initial findings be available during this IRP process?
d. Is this the same study referenced on page 82 of 1182 of the IRP that is being conducted by GDS Associates?
e. Will this study evaluate demand response potential, both active and passive?
i. If not, please explain why demand response has been excluded.

RESPONSE

a. The Company contracted with GDS in August of 2022 to perform the Market Potential Study (MPS).

b. Please see the Company's response to KPSC 1-52(a). The Company anticipates that the MPS will be completed by the end of June 2023.

c. The Company objects to this request on the grounds that the term "initial findings" is ambiguous. The Company construes the term to refer to finding provided by GDS prior to the filing of the final report with the Commission. The Company anticipates that the MPS will be completed by the end of June 2023. Pursuant to the Commission's January 6, 2023 Order in Case No. 2022-00392, the Company will file the final MPS into the record of that case.

d. Yes, the MPS referenced on page 82 is the same MPS referenced on page 64.

e. See the Company's response to KPSC 1-52(b).

Witness: Brian K. West

Witness: Jeffrey Huber

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DATA REQUEST

JI 1_30 Please provide the analysis, results, and decisions related to the benchmarking exercise discussed on page 82 of 1182 of the IRP in a fully functional electronic format, with all workpapers for the benchmarking exercise provided in fully functional Excel format with formulas intact.
a. Did this benchmarking exercise consider demand response?
i.If it did, please provide a table for demand response like that provided in Table 4.
ii. If not, please explain why demand response was excluded.

RESPONSE

The attached workbook KPCO_R_JI_1_30_Attachment1 provides the benchmarking analysis. There are two tabs: "MPS Benchmarking" and "EIA Benchmarking." The MPS Benchmarking tab provides the annual savings as a percentage of sales from the two MPS studies completed by GDS as referenced in the IRP (for other clients in Indiana and Kentucky). The average annual savings is 1.3% (~1%) for both studies. The EIA Benchmarking tab provides the EIA Form 861 data from 2020 used to determine the average savings were approximately 1.0% in 2020. Cells BE508:BH508 highlighted in green show how the analysis was conducted.

a. The benchmarking analysis did not consider demand response for the reasons discussed in the Company's response to KPSC 1-52(b).

Witness: Jeffrey Huber

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DATA REQUEST

JI 1_31 On page 82 of 1182 of the IRP, GDS Associates assumed that Kentucky Power could ramp up to 1% annual savings over 4 years.
a. What is the basis for this assumption? Please include any workpapers or analysis related to this determination.
b. Please explain how this assumption accounts for the current lack of energy efficiency programs.

RESPONSE

a. The 1% annual savings was informed by the benchmarking analysis shown in KPCO_R_JI_1_30_attachment1. The 4-year ramp-up timeframe is based on the professional judgment and experience of GDS.

b. This assumption acknowledges the current lack of programs and recognizes that a well designed and funded portfolio of energy efficiency programs can reach 1% of savings over a reasonable timeframe, considering that the average annual energy savings is approximately 1% per year in 2020. Please also see the Company's response to KPSC 1-52.

Witness: Jeffrey Huber

DATA REQUEST

JI 1_32 On page 83 of 1182 of the IRP, it is stated that the energy efficiency cost inputs for the IRP are from the benchmarking exercise which leveraged the results of a recent potential study.

a. Please provide the potential study that GDS leveraged in a fully functional electronic format.

b. Please provide all workpapers for the study in fully functional Excel format with formulas intact.

RESPONSE

a & b. The potential study that GDS referred to for this IRP is a recent effort completed for a client in Indiana. GDS modified the results of that study by changing the benefit-cost screening test used to evaluate cost-effectiveness from the Utility Cost Test (UCT) to the Total Resource Cost (TRC) Test because the TRC Test is the primary benefit-cost test used to evaluate energy efficiency programs in Kentucky. The results of the modifications that were used in the IRP are reflected in KPCO_R_JI_1_32 Attachment1 which provides a workpaper showing the modified outputs of the referenced study and the calculated inputs used for bundle cost development in the IRP.

Witness: Jeffrey Huber

DATA REQUEST

JI 1_33 Reference page 83 of 1182 of the IRP, Section 4.2.1 Determination of Bundles, please detail:
a. Was lighting included in any of the bundles? If so, please identify the bundle and types of lighting.
b. For each bundle, please detail the measures and level of efficiency assumed with those measures.
c. Please provide the rationale behind the $/MWh costs for each bundle.
d. Do any of the bundles consider demand reductions, passive or active?

RESPONSE

a. The IRP inputs were based on a benchmarking analysis as noted in the IRP. The bundle disaggregation was based on the results of a previous GDS potential study in Indiana. In the benchmarked potential studies, the residential lighting savings were significantly limited due to codes and standards and market transformation. In the C&I sector, significant lighting opportunities did remain in the benchmarked potential studies.

b. The benchmarking analysis was not done at an end-use or measure level.

c. Please see the Company's response to JI 1_32.

d. No active demand response was included. Any peak demand reductions are reflected in the 8760 hourly profile of each bundle.

Witness: Jeffrey Huber

DATA REQUEST

JI 1_34 Please provide the data behind Figure 13 EE IRP Bundles – MWh Savings Potential (page 85 of 1182 of the IRP).
a. Please provide a similar table with the demand reduction potential.

RESPONSE

Please see KPCO_R_JI_1_34_Attachment1

Witness: Jeffrey Huber

DATA REQUEST

JI 1_35 In relation to the energy efficiency assumptions, particularly regarding cooling load, please detail the assumptions related to the Inflation Reduction Act rebates and tax credits. If this was not considered, please explain.

a. As part of its analysis of the Inflation Reduction Act for this IRP, did the Company consider potential increases in load because of electrification? If so, please explain how.

RESPONSE

During the development of the load forecast used in this IRP, the details of the Inflation Reduction Act were not fully known, and therefore were not considered.

Witness: Glenn R. Newman

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DATA REQUEST

JI 1_36 As part of the energy efficiency and code assumptions, did the model consider impacts resulting from federal funding, including the American Rescue Plan[8] and Bipartisan Infrastructure Law?[9] Please explain in detail why or why not.

[8] American Rescue Plan Act of 2021, Pub. L. No. 117-2, 135 Stat. 4.
[9] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).

RESPONSE

No, for this IRP the energy efficiency resources modeled were informed from a top down benchmarking analysis where the potential impacts of these federal programs were not practical to consider.

Witness: Jeffrey Huber

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DATA REQUEST

JI 1_37 Given the Company's projected capacity purchases and capacity shortfall projected in this IRP, please explain in detail why the Company has not yet sought Commission approval for any new proposed DSM programs.
a. Does the Company anticipate seeking Commission approval for any new proposed DSM programs in the next three years? Please explain in detail why or why not.

RESPONSE

See the Company's response to KPSC 1-52.

Witness: Brian K. West

DATA REQUEST

JI 1_38 Please refer to page 62 of 1182 of the IRP where Kentucky Power indicates that there are 6.2 MW of peak DR capability. What are the rules surrounding this demand response capacity? If it is in a tariff, please reference where it can be found in the tariff.

RESPONSE

Please see Kentucky Power's Rider D.R.S. (Demand Response Service, Tariff Sheet No. 36) and Tariff C.S.-I.R.P. (Contract Service – Interruptible Power, Tariff Sheet No. 12).

Witness: Brian K. West

DATA REQUEST

JI 1_39 Please refer to page 42 of 1182 of the IRP, where it says, “The Company’s load forecast does not reflect any on-going adjustments for DSM” and “For this load forecast, there was no DSM/EE included.” Please confirm if these statements are related to addressing historical energy efficiency savings or new energy efficiency savings.

RESPONSE

The Company did not adjust the load forecast for new DSM/EE as it does not have programs filed with the Commission providing a significant impact. The only program the Company has that has been approved by the Commission has minimal impact on load.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_40 Please refer to page 47 of 1182 of the IRP, where it states, "The sharp increase in commercial energy sales is associated with the addition a large industrial customer with significant energy requirements."
a. Please confirm if this refers to the addition of a cryptocurrency customer to Kentucky Power's service territory. If not, please identify the large industrial customer that is referenced.
b. Please explain how Kentucky Power treated the projected load from the proposed Ebon facility for this IRP.[10]

[10] *See In re: Special Contract Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Case No. 2022-00387.

RESPONSE

a. and b. Please see KPCO_R_JI_1_40_ConfidentialAttachment1 for the requested information.

Witness: Glenn R. Newman

Attachment is redacted in its entirety.

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DATA REQUEST

JI 1_41 Please refer to Section 3.2 on page 54 of 1182 of the IRP.
a. Please confirm if Kentucky Power included the 14.7% IRM or the PJM FPR of 8.9% as the planning reserve margin in AURORA.
b. Please confirm if Kentucky Power is modeling existing and new thermal resources on a UCAP or ICAP basis.

RESPONSE

a) The Company used the PJM Forecast Pool Reserve (FPR) Of 8.9% as the planning reserve margin to align to its capacity obligation relative to a UCAP basis.

b) The Company modeled capacity obligations on a UCAP basis.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_42 Please refer to Section 4.2.1 and 4.2.2 of 1182 of the IRP.
a. Please provide all supporting workbooks, with formulas and links intact, used to develop the energy efficiency savings and cost for each residential and C&I bundle modeled in AURORA.
b. Please provide all supporting workbooks, with formulas and links intact, used to group the energy efficiency measures into each of the residential and C&I bundles modeled in AURORA.
c. Please provide the line loss factor that Kentucky Power used to adjust energy efficiency savings from the meter to the generator.
d. Please explain if the income qualified energy efficiency bundles were modeled as selectable within AURORA or as a fixed resource decision in the model.

RESPONSE

a-c. Please see attachment KPCO_R_JI_1_42_Attachment1

d. Income qualified EE bundles were modeled as a fixed resource decision in all Portfolios.

Witness: Jeffrey Huber

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DATA REQUEST

JI 1_43 Please refer to pages 92-93 of 1182 of the IRP for the costs of battery storage resources.
a. Please confirm if the capital cost assumptions and the Fixed O&M are from the EIA AEO or the NREL ATB.
b. Please provide the project life that was modeled for Li-ion batteries.
c. Please provide any battery augmentation assumptions that Kentucky Power made for the Li-ion batteries modeled in AURORA.

RESPONSE

a. Initial capital costs and Fixed O&M were informed from the EIA AEO, and forecasted costs were developed from the NREL ATB learning curves.

b. 10 years.

c. Battery augmentation assumptions are included in the FO&M costs from the EIA. This includes a 3% battery augmentation factor.

Witness: Thomas Haratym

DATA REQUEST

JI 1_44 Please refer to Figure 21 on page 95 of 1182 of the IRP. Please confirm if the Fixed O&M for new wind resources is from the EIA AEO[11] or the NREL ATB.[12]

[11] U.S. Energy Information Administration, *Annual Electric Power Industry Report, Form EIA-861* (Oct. 6, 2022), https://www.eia.gov/electricity/data/eia861/.
[12] NREL Electricity Annual Technology Baseline (ATB) 2022, https://atb.nrel.gov/electricity/2022/data (last visited May 22, 2023).

RESPONSE

Fixed O&M for new wind resource is from EIA AEO 2022 using the cost reduction curve from NREL ATB 2022.

Witness: Thomas Haratym

DATA REQUEST

JI 1_45 Please refer to Section 5.4.1 and 5.4.2 of the IRP on the costs of new wind and solar resources.
a. Please explain if the costs for new wind and solar resources were modeled within AURORA on a levelized $/MWH basis or if the "FOM $/MW-week" input field within AURORA was used.
b. Please provide the supporting workbooks, with all formulas and links intact, used to develop the cost inputs for new resources as they are modeled in AURORA.
c. Please provide the following input tables from the AURORA model:
i. New Resources;
ii. Resources;
iii. Storage;
iv. Annual, Monthly, and Hourly Time Series.

RESPONSE

a. Costs for new wind and solar resources were modeled employing AURORA's "FOM $/MW-week" field.

b. Please see KPCO_R_KPSC_1_8_ConfidentialAttachment6 and KPCO_R_KPSC_1_8_Attachment2.

c. Please see KPCO_R_KPSC_1_8_Attachment2 and KPCO_R_KPSC_1_8_ConfidentialAttachment6 for key resource operating and cost inputs for each technology.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_46 Please refer to page 94 of 1182 of the IRP, where it states, "Both the hourly production profile and average capacity factor are estimated based on AURORA national database information representative of resources in the region."

a. Please provide the region that was defined for developing the capacity factor for new wind resources.

b. Please explain in detail if Kentucky Power is modeling new wind resources with the assumption that wind would be built within Kentucky or if projects would be from outside of the state (or both).

RESPONSE

a. The 35% capacity factor assumed for wind resources in this IRP was indicative of wind resource in surrounding areas to the Kentucky Power territory.

b. For this IRP, a specific location of where wind might be built was not assumed for the purposes of modeling. The Company will issue an RFP to identify potential projects both within Kentucky as well as outside of the state.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_47 Please refer to Section 5 of the IRP.
a. Please explain in detail how Kentucky Power developed the annual and cumulative maximum build constraints for battery storage, wind, and solar resources modeled in AURORA.
b. Please provide the supporting workbooks, with all formulas and links intact, for Figures 18, 19, 20, 21, 22, and 23.
c. For each of the new generating resources modeled in AURORA, please provide the inflation rate assumed to translate the capital and fixed O&M costs from real to nominal dollars.

RESPONSE

a. Kentucky Power identified renewable build limits that were informed by resources in the PJM queue as of Nov 2, 2022.

b. and c. Please see KPCO_R_KPSC_1_8_Attachment2.

Witness: Thomas Haratym

DATA REQUEST

JI 1_48 Please refer to Figure 35 on page 111 of 1182 of the IRP.
a. Please provide the source of the PJM Capacity Price Outlook shown in Figure 35.
b. Please provide the supporting workbook, with all formulas and links intact, used to develop the capacity prices shown in Figure 35.

RESPONSE

a. See the response to KPSC 1_51a.

b. Please refer to KPCO_R_KPSC_1_8_Attachment2, Capacity Price worksheet.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_49

RESPONSE

Number 49 was skipped in the questions provided and thus no response is provided.

Witness: Counsel

DATA REQUEST

JI 1_50 Please refer to page 112 of 1182 of the IRP, where it states, "Kentucky Power has modeled portfolio adequacy in both the summer and winter seasons for this integrated resource planning process."
a. Please explain if this means that Kentucky Power modeled a summer and a winter reserve margin in AURORA or if Kentucky Power evaluated portfolios after they were developed within AURORA to see if they met a winter reserve margin requirement.
b. Please provide the reserve margin that Kentucky Power assumed for the winter.

RESPONSE

a. As discussed in Section 7.3.2 in the IRP, Kentucky Power evaluated an optimized build under Reference conditions to assess a hypothetical requirement for winter peak adequacy. Additionally, Kentucky Power evaluated the summer optimized portfolios to understand their respective capacity positions relative to a hypothetical company winter peak adequacy requirement as reflected in the Planning Reserves metric in the IRP Scorecard.

b. 8.94%.

Witness: Thomas Haratym

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DATA REQUEST

JI 1_51 Please refer to page 113 of 1182 of the IRP, where it states, "For modeling purposes, Kentucky Power modeled generic interconnection costs for resource evaluation based on a recent LBL study."
a. Please provide the interconnection costs modeled for each of the new supply side resources modeled in AURORA.
b. Please provide the supporting workbook, with all formulas and links intact, used to develop the interconnection costs modeled for each new supply side resource.

RESPONSE

a. An interconnection cost of $18.9/kW capex was included for each resource.

b. Interconnection costs was derived from the PJM report included as KPCO_R_JI_1_51_Attachment1.

Witness: Thomas Haratym

PJM CONE 2026/2027 Report

PREPARED BY

Samuel A. Newell
J. Michael Hagerty
Johannes Pfeifenberger
Bin Zhou
Travis Carless
Rohan Janakiraman
The Brattle Group

Sang H. Gang
Patrick S. Daou
Joshua C. Junge
Sargent & Lundy

PREPARED FOR

PJM Interconnection

APRIL 21, 2022

DATE

NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

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Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

Background

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

Reference Resource

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of "clean capacity" for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two "single-shaft 1x1"s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

 Cost Analysis

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation: Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

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[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of $209/MW-day for the RTO, $222 for MAAC, $189 for EMAAC, and $249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about $10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

Implications for Net CONE and VRR Curve

Elevated Net CONE. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at $307/MW-day for the RTO, $294 for MAAC, $329 for EMAAC, and $257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about $154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

Slightly elevated VRR Curve. In spite of significant cost increases, updated CC Net CONE is only $47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

I. Introduction

I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one "clean technology" in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

[3] The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

[4] PJM 2017 OATT, Section 5.10 a.

[5] PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

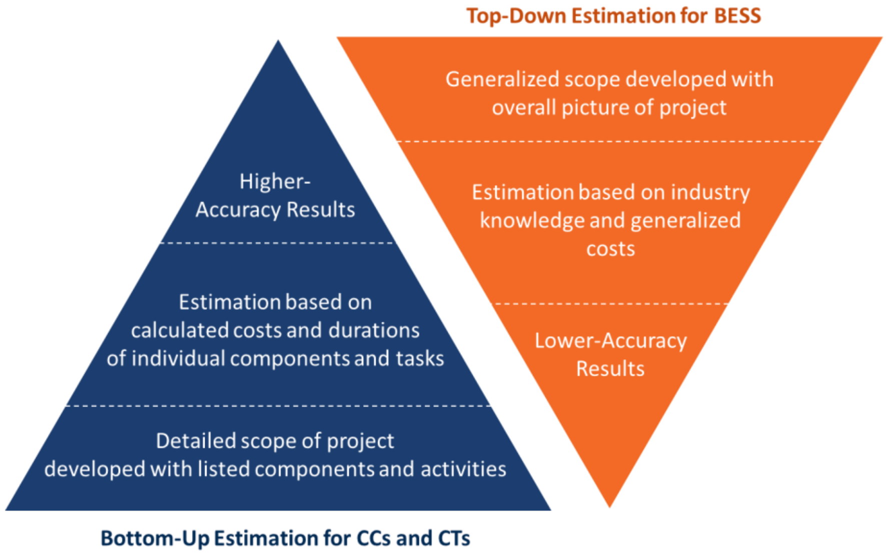
I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS



Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

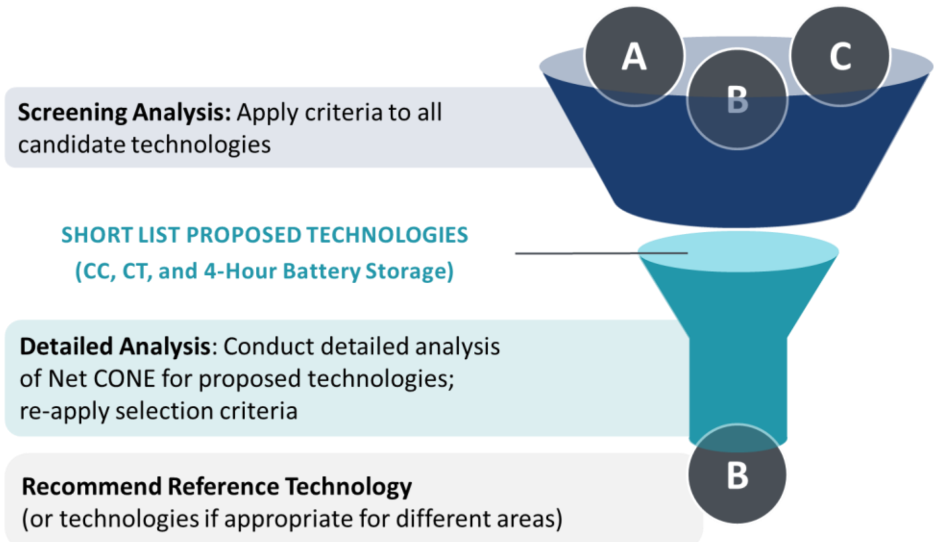
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible "clean technology" for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on "empirical Net CONE," i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA

Feasible to build for the delivery year, given local laws/regulations and technical factors

Economic source of incremental capacity
- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately
- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for "accuracy" should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs' net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes**	**Yes** (significant recent entry; lowest 2026/27 Net CONE)	**Highest**
Gas CT	**Yes** (may be infeasible to build in NJ)	**Unclear** (few recently built; Net CONE 20% higher than CC)	**High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch)
Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates)	**Low** (uncertain future AS revenues; falling costs)

We also considered "empirical Net CONE" based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

6 For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

7 The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

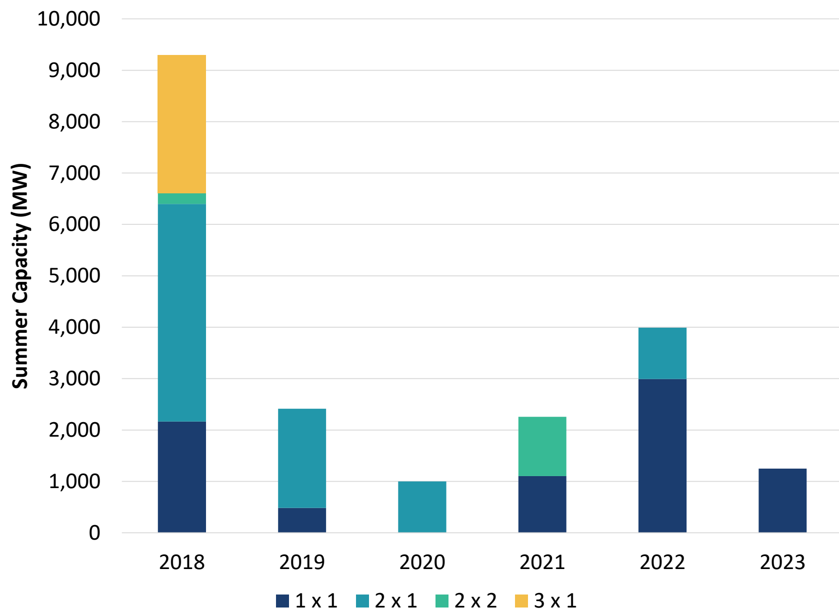
Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

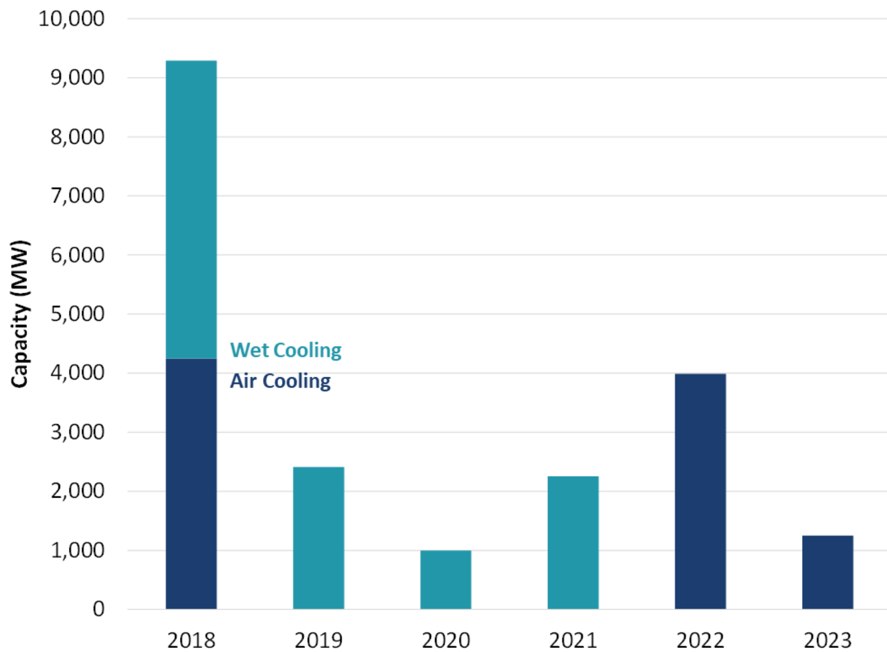
III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize “wet” cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

III.A.3. Emissions Controls

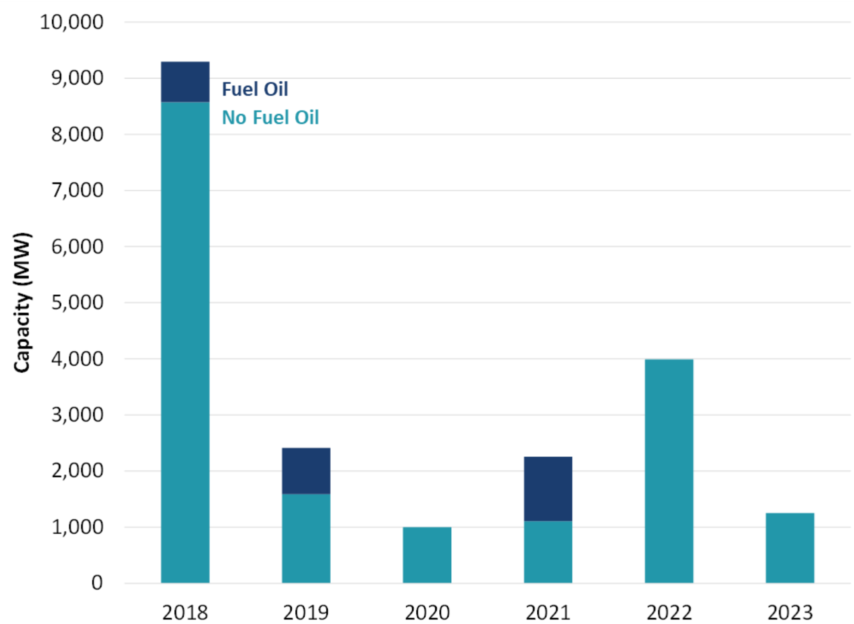
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with "dual-fuel" capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

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[9] Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

[10] PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1171 MW*	*1174 MW*	*1144 MW*	*1133 MW*
Owner Furnished Equipment				
Gas Turbines	$155.3	$155.3	$155.3	$155.3
HRSG / SCR	$80.7	$80.7	$80.7	$80.7
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$320.7**	**$320.7**	**$320.7**	**$320.7**
EPC Costs				
Equipment				
Other Equipment	$86.3	$86.3	$86.3	$86.3
Construction Labor	$365.5	$283.3	$297.1	$330.5
Other Labor	$75.5	$69.0	$70.1	$72.7
Materials	$75.5	$75.5	$75.5	$75.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$98.5	$89.6	$91.1	$94.7
EPC Contingency	$108.4	$98.6	$100.2	$104.2
Total EPC Costs	**$871.4**	**$763.9**	**$782.0**	**$825.6**
Non-EPC Costs				
Project Development	$59.6	$54.2	$55.1	$57.3
Mobilization and Start-Up	$11.9	$10.8	$11.0	$11.5
Net Start-Up Fuel Costs	-$13.9	-$14.0	-$9.8	-$13.5
Electrical Interconnection	$25.3	$25.4	$24.7	$24.5
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$2.2	$1.8	$1.0	$1.8
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$6.0	$5.4	$5.5	$5.7
Owner's Contingency	$10.0	$9.4	$9.7	$9.7
Emission Reduction Credit	$2.3	$2.3	$2.3	$2.3
Financing Fees	$29.2	$26.7	$27.2	$28.1
Total Non-EPC Costs	**$166.4**	**$155.8**	**$160.6**	**$161.3**
Total Capital Costs	**$1,358.5**	**$1,240.5**	**$1,263.3**	**$1,307.6**
Overnight Capital Costs ($million)	**$1,359**	**$1,240**	**$1,263**	**$1,308**
Overnight Capital Costs ($/kW)	**$1,160**	**$1,057**	**$1,104**	**$1,154**
Installed Cost ($/kW)	**$1,255**	**$1,144**	**$1,195**	**$1,248**

III.B.1. EPC Capital Costs

III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

III.B.1.ii. **Equipment and Materials**

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

III.B.1.iii. **Labor**

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

III.B.1.iv. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

III.B.2.i. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

III.B.2.v. Land

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC

CONE Area	Land Price *($/acre)*	Plot Size Gas CC *(acres)*	Cost Gas CC *($m)*
1 EMAAC	$36,600	60	$2.20
2 SWMAAC	$29,500	60	$1.77
3 Rest of RTO	$16,400	60	$0.98
4 WMAAC	$30,600	60	$1.84

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

III.B.2.vi. Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.vii. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.00%	2.91%
Labor	1.60%	4.51%

Sources and notes: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

[13] The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *1171 MW*	2 SWMAAC *1174 MW*	3 Rest of RTO *1144 MW*	4 WMAAC *1133 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.8	$0.8	$0.8	$0.8
Labor	$5.2	$5.6	$4.0	$4.1
Maintenance and Minor Repairs	$6.6	$6.7	$6.0	$6.1
Administrative and General	$1.4	$1.4	$1.2	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.2
Property Taxes	$3.0	$16.4	$9.5	$2.9
Insurance	$8.2	$7.4	$7.6	$7.8
Firm Gas Contract	$10.0	$12.4	$16.4	$14.5
Working Capital	$0.2	$0.1	$0.1	$0.1
Total Fixed O&M (2026$ million)	**$36.8**	**$52.6**	**$46.8**	**$38.8**
Levelized Fixed O&M (2026$/MW-yr)	**$31,500**	**$44,900**	**$40,900**	**$34,200**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	0.76	0.76	0.77	0.77
Total Variable O&M (2026$/MWh)	**2.08**	**2.07**	**2.12**	**2.14**

III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

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[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

	Real Property Tax	Personal Property Tax	
	Effective Tax Rate	Effective Tax Rate	Depreciation
	(%)	*(%)*	*(%/yr)*
1 EMAAC			
New Jersey	3.8%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.3%	3.30%
3 RTO			
Ohio	1.9%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	2.7%	n/a	n/a
4 WMAAC			
Pennsylvania	3.8%	n/a	n/a

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

III.C.2.iv. Working Capital

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

III.C.2.v. Firm Transportation Service Contracts

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

15 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

	CONE Area	Pipelines	Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)*
1	**EMAAC**	Transco Zone 6 (non-NY), Transco Zone 6 (NY)	$4.50
2	**SWMAAC**	Dominion Cove Point	$5.56
3	**Rest of RTO**	Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5	$7.54
4	**WMAAC**	Tennessee 500L, TETCO M3	$6.73

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

III.D. Financial Assumptions

III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

[16] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

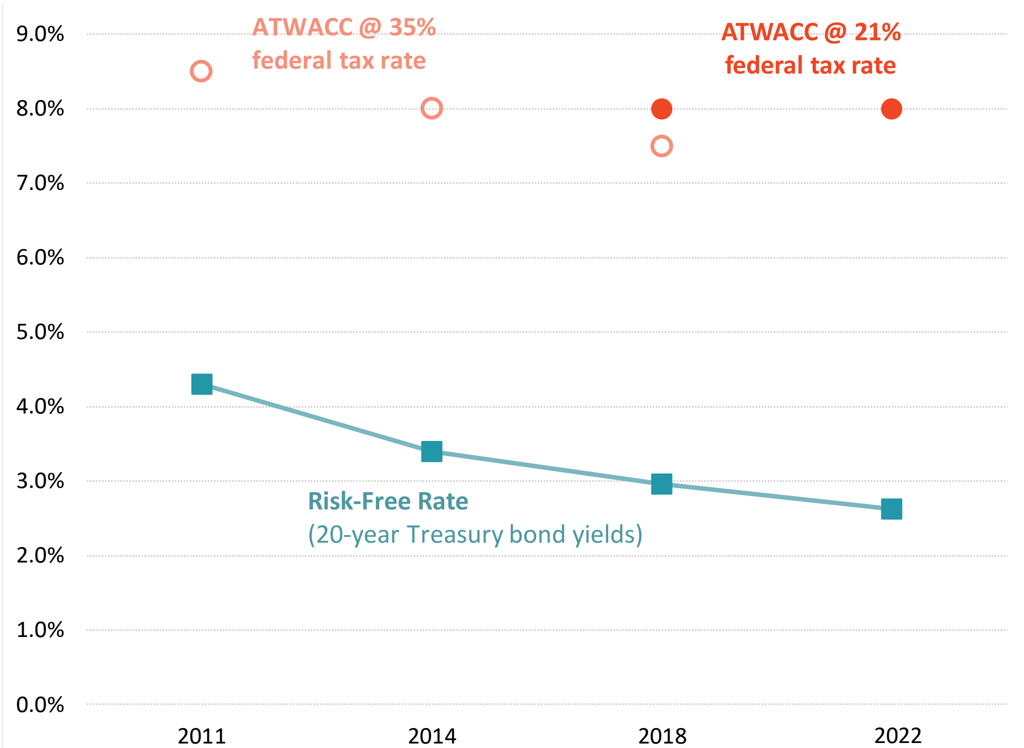
[17] Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

[18] $4.7\% \times 55\% \times (1 - 27.7\%) + 13.6\% \times 45\% = 8.0\%$. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes ($= 8.5\% + (1 - 8.5\%) \times 21\%$). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM



Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS

Study Year	Tax Rate	Return on Equity	Equity Ratio	Cost of Debt	Debt Ratio	ATWACC
2011	40.5%	12.5%	50%	7.5%	50%	8.5%
2014	40.5%	13.8%	40%	7.0%	60%	8.0%
2018	27.7%	13.0%	45%	5.5%	55%	8.0%
2022	27.7%	**13.6%**	45%	**4.7%**	55%	8.0%

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of March 31, 2022: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

TABLE 13: BASE-CASE ATWACC - 2022

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,862	$17,754	1.10	10.8%	41%	4.3%	6.3%
NRG Energy Inc	BB+	$9,179	$8,202	1.15	11.2%	53%	4.9%	7.6%
Vistra Corp	BB	$10,117	$10,515	1.10	10.8%	47%	5.2%	7.1%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Sample: Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019

Company [1]	Retail [2]	Generation [3]
NRG	38%	62%
Vistra	8%	92%

[21] NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

[22] AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

Cost of Equity: We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

Cost of Debt: In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	2.5%	4.3%
NRG Energy Inc	BB+	2.8%	4.9%
Vistra Corp	BB	3.1%	5.2%

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

Debt/Equity Ratio: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

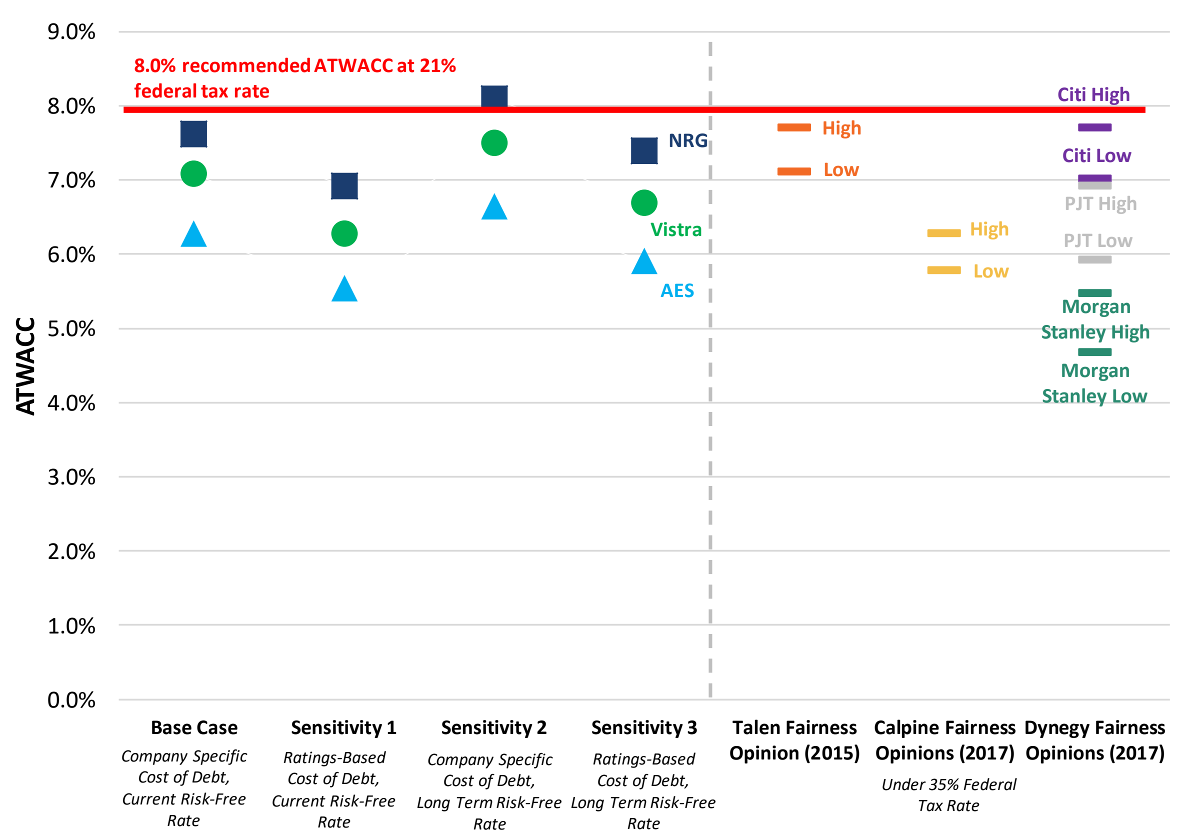
ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES



Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

29 Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

30 Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

31 This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

TABLE 16: STATE CORPORATE INCOME TAX RATES

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	11.50%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%

Sources and notes: State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

[32] The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

[33] Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit CO_2 emissions for new gas generation units to below 860 lbs CO_2/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

III.F. CONE Results and Comparisons

III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

Sources and notes: CONE values expressed in 2026 dollars and ICAP terms.

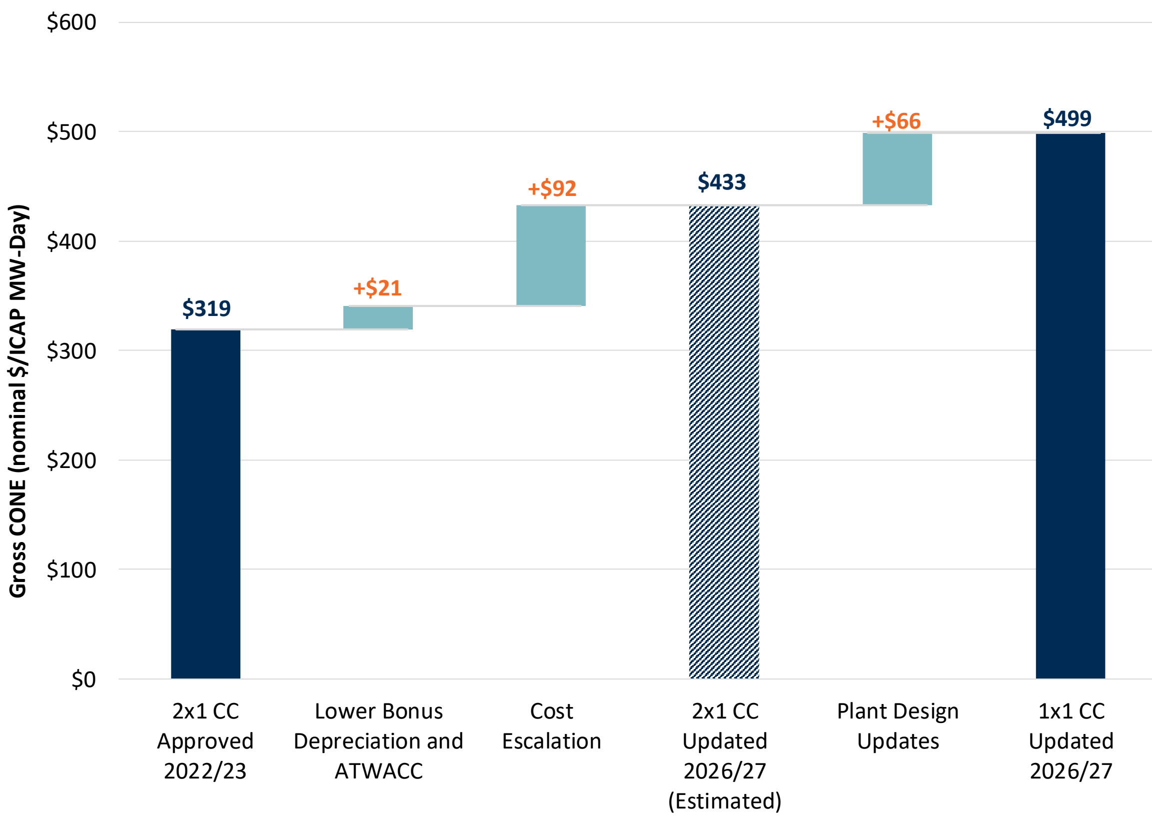
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX

	Combustion Turbine			Combined Cycle		
Component	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index
Labor	20%	30%	30%	25%	43%	40%
Materials	50%	45%	45%	60%	45%	45%
Turbine	30%	25%	25%	15%	12%	15%

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

III.I. Implications for Net CONE

III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

[38] Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	CC			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$168	$2	-$24	$146
DPL	$216	$3	-$23	$196
JCPL	$166	$2	-$24	$143
PECO	$184	$14	-$23	$174
PSEG	$162	$2	-$24	$140
RECO	$172	$2	-$23	$151
CONE Area 2				
BGE	$254	$4	-$20	$239
PEPCO	$197	$10	-$21	$185
CONE Area 4				
METED	$212	$15	-$22	$205
PENELEC	$320	$7	-$17	$310
PPL	$190	$15	-$22	$182
CONE Area 3				
AEP	$242	$8	-$21	$229
APS	$281	$5	-$19	$267
ATSI	$208	$44	-$21	$231
COMED	$179	$11	-$22	$168
DAY	$223	$45	-$21	$247
DEOK	$214	$43	-$21	$237
DUQ	$225	$15	-$20	$219
DOM	$195	$9	-$21	$183
EKPC	$246	$14	-$21	$239
RTO	**$189**	**$11**	**-$23**	**$177**

Note: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The "Updated 2023/24 EAS" values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	CC 2022/23 MOPR			CC 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$335	$167	$163	$517	$174	$343
DPL	$335	$208	$122	$517	$231	$286
JCPL	$335	$165	$165	$517	$172	$346
PECO	$335	$186	$144	$517	$206	$311
PSEG	$335	$161	$169	$517	$168	$349
RECO	$335	$171	$159	$517	$180	$337
EMAAC	**$335**	**$181**	**$154**	**$517**	**$189**	**$329**
CONE Area 2						
BGE	$345	$254	$76	$506	$279	$227
PEPCO	$345	$191	$139	$506	$219	$287
SWMAAC	**$345**	**$238**	**$107**	**$506**	**$249**	**$257**
CONE Area 4						
METED	$323	$207	$123	$522	$241	$281
PENELEC	$323	$306	$24	$522	$359	$163
PPL	$323	$185	$145	$522	$216	$307
MAAC	**$334**	**$204**	**$130**	**$517**	**$222**	**$294**
CONE Area 3						
AEP	$316	$233	$97	$518	$268	$251
APS	$316	$272	$58	$518	$311	$208
ATSI	$316	$224	$106	$518	$271	$248
COMED	$316	$195	$135	$518	$199	$319
DAY	$316	$235	$95	$518	$288	$230
DEOK	$316	$224	$106	$518	$277	$242
DUQ	$316	$223	$107	$518	$257	$261
DOM	$316	$181	$149	$518	$216	$303
EKPC	$316	$232	$98	$518	$279	$239
OVEC	$316	$260	$70	$518	$303	$216
RTO	**$330**	**$185**	**$146**	**$516**	**$209**	**$307**

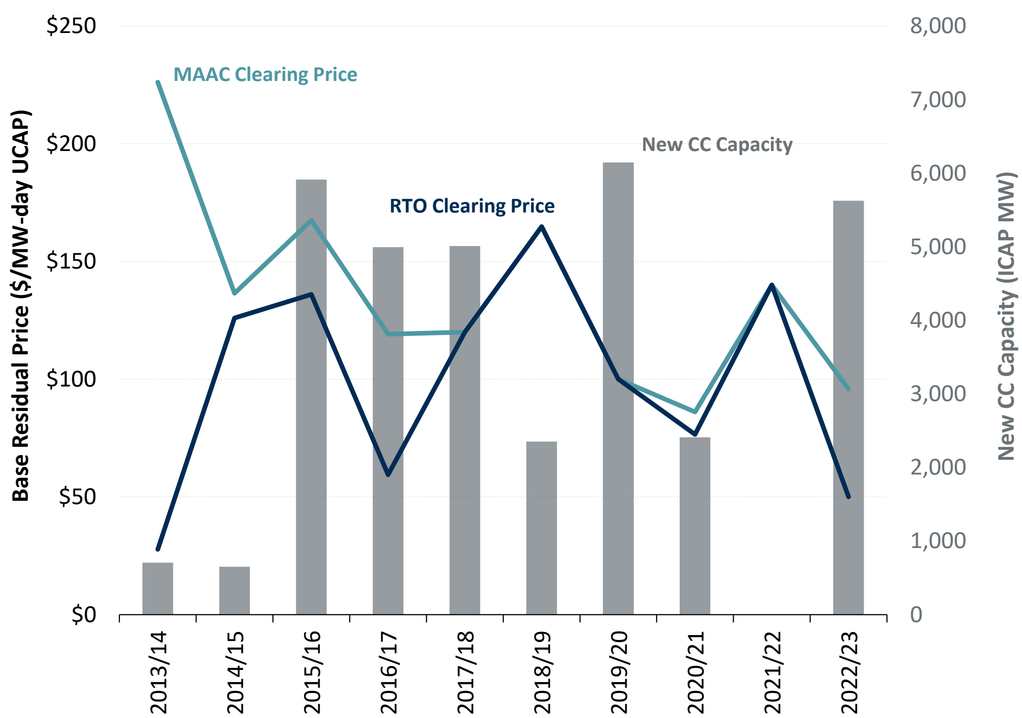
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY



Sources and notes: PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	Turbine Class	PJM		US	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 10 acres of land are for the reference CT.

TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT

CONE Area	Land Price (\$/acre)	Plot Size Gas CT (acres)	Cost Gas CT (\$m)
1 EMAAC	$36,600	10	$0.37
2 SWMAAC	$29,500	10	$0.30
3 Rest of RTO	$16,400	10	$0.16
4 WMAAC	$30,600	10	$0.31

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*361 MW*	*363 MW*	*353 MW*	*350 MW*
Owner Furnished Equipment				
Gas Turbines	$78.6	$78.6	$78.6	$78.6
HRSG / SCR	$33.5	$33.5	$33.5	$33.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$112.1**	**$112.1**	**$112.1**	**$112.1**
EPC Costs				
Equipment				
Other Equipment	$24.1	$24.1	$24.1	$24.1
Construction Labor	$50.6	$37.8	$40.6	$45.0
Other Labor	$16.4	$15.4	$15.6	$16.0
Materials	$8.1	$8.1	$8.1	$8.1
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$21.1	$19.8	$20.1	$20.5
EPC Contingency	$23.2	$21.7	$22.1	$22.6
Total EPC Costs	**$143.6**	**$127.0**	**$130.6**	**$136.3**
Non-EPC Costs				
Project Development	$12.8	$12.0	$12.1	$12.4
Mobilization and Start-Up	$2.6	$2.4	$2.4	$2.5
Net Start-Up Fuel Costs	-$0.6	-$0.6	$0.1	-$0.5
Electrical Interconnection	$7.8	$7.8	$7.6	$7.6
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$0.4	$0.3	$0.2	$0.3
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$1.3	$1.2	$1.2	$1.2
Owner's Contingency	$4.6	$4.6	$4.6	$4.6
Emission Reduction Credit	$0.0	$0.0	$0.0	$0.0
Financing Fees	$7.0	$6.6	$6.7	$6.8
Total Non-EPC Costs	**$69.6**	**$68.0**	**$68.7**	**$68.6**
Total Capital Costs	**$325.3**	**$307.1**	**$311.4**	**$317.0**
Overnight Capital Costs ($million)	**$325**	**$307**	**$311**	**$317**
Overnight Capital Costs ($/kW)	**$902**	**$846**	**$882**	**$906**
Installed Cost ($/kW)	**$945**	**$887**	**$925**	**$949**

IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *361 MW*	2 SWMAAC *363 MW*	3 Rest of RTO *353 MW*	4 WMAAC *350 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.3	$0.3	$0.3	$0.3
Labor	$1.2	$1.2	$0.9	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.3	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$2.2	$0.3
Insurance	$2.0	$1.8	$1.9	$1.9
Firm Gas Contract	$4.4	$5.4	$7.1	$6.3
Working Capital	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2026$ million)	**$9.5**	**$14.4**	**$13.5**	**$10.9**
Levelized Fixed O&M (2026$/MW-yr)	**$26,300**	**$39,600**	**$38,300**	**$31,300**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	1.19	1.18	1.15	1.22
Total Variable O&M (2026$/MWh)	**1.19**	**1.18**	**1.15**	**1.22**
Major Maintenance - Starts Based ($/factored start, per turbine)	**21,170**	**21,170**	**21,170**	**21,170**

IV.D. CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

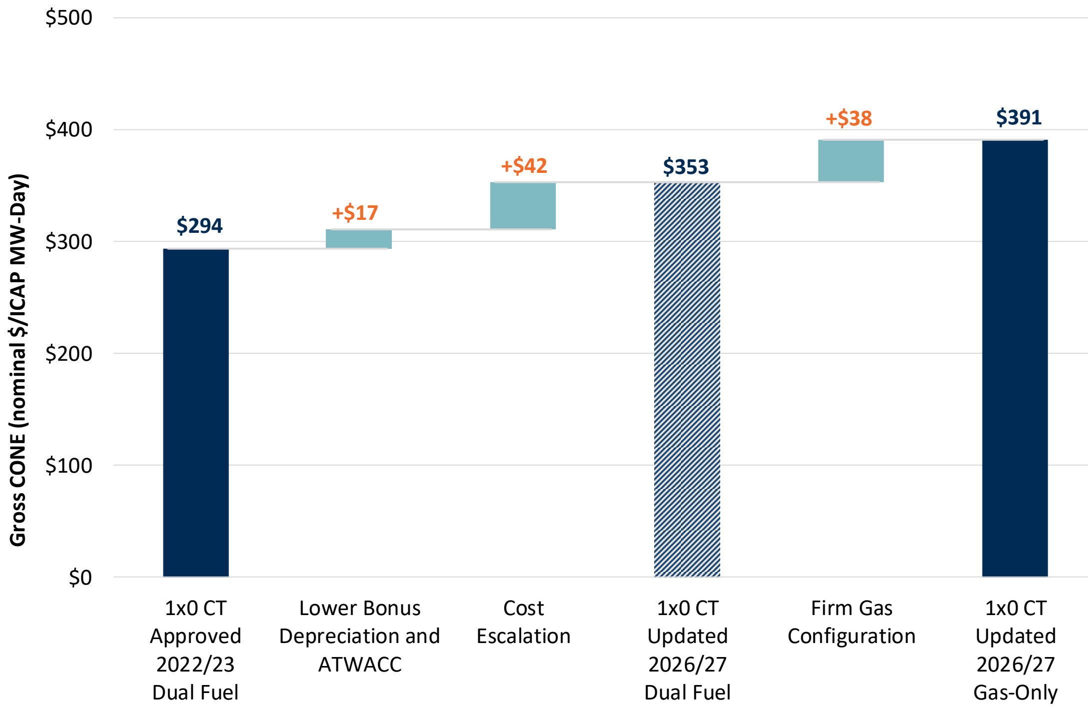
TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$325	$307	$311	$317
[2]	Installed (inc. IDC)	*$m*		$341	$322	$326	$332
[3]	First Year FOM	*$m/yr*		$9	$14	$14	$11
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$902	$846	$882	$906
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$945	$887	$925	$949
[7]	Levelized FOM	*$/kW-yr*		$33	$44	$45	$39
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		11.7%	11.6%	11.6%	11.6%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$138,000**	**$141,700**	**$147,100**	**$144,000**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$378**	**$388**	**$403**	**$395**

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

IV.E. Implications for Net CONE

IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, "PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[41] This time, we are not recommending a "10% adder" that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

[41] 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

All values in nominal $/MW-day ICAP	CT			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$45	-$4	-$8	$33
DPL	$76	-$2	-$8	$65
JCPL	$43	-$4	-$8	$32
PECO	$48	$4	-$7	$45
PSEG	$41	-$4	-$8	$30
RECO	$48	-$3	-$8	$36
CONE Area 2				
BGE	$93	$6	-$9	$89
PEPCO	$57	-$1	-$7	$49
CONE Area 4				
METED	$65	$8	-$8	$65
PENELEC	$150	$28	-$12	$166
PPL	$52	$5	-$7	$49
CONE Area 3				
AEP	$83	$9	-$12	$79
APS	$114	$17	-$13	$118
ATSI	$66	$16	-$8	$75
COMED	$47	-$6	-$7	$34
DAY	$70	$21	-$8	$83
DEOK	$74	$17	-$8	$83
DUQ	$81	$15	-$8	$89
DOM	$56	-$1	-$7	$48
EKPC	$80	$11	-$10	$81
RTO	**$48**	**-$1**	**-$8**	**$39**

Sources and notes: The “Current 2023/24 E&AS” reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The “Updated 2023/24 EAS” values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC’s zone.

IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 28: INDICATIVE 2026/27 CT NET CONE

All values in nominal $/MW-day UCAP	CT 2022/23 BRA			CT 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$312	$47	$265	$397	$48	$349
DPL	$312	$76	$236	$397	$85	$312
JCPL	$312	$45	$267	$397	$47	$351
PECO	$312	$54	$258	$397	$62	$336
PSEG	$312	$43	$268	$397	$44	$353
RECO	$312	$50	$262	$397	$52	$346
EMAAC	**$312**	**$52**	**$259**	**$397**	**$56**	**$341**
CONE Area 2						
BGE	$317	$90	$226	$408	$113	$315
PEPCO	$317	$57	$260	$408	$67	$315
SWMAAC	**$317**	**$74**	**$243**	**$408**	**$93**	**$315**
CONE Area 4						
METED	$305	$67	$238	$415	$85	$315
PENELEC	$305	$139	$166	$415	$200	$210
PPL	$305	$54	$250	$415	$67	$315
MAAC	**$311**	**$66**	**$245**	**$404**	**$79**	**$320**
CONE Area 3						
AEP	$305	$77	$227	$424	$101	$315
APS	$305	$102	$203	$424	$146	$315
ATSI	$305	$74	$230	$424	$96	$315
COMED	$305	$57	$248	$424	$49	$421
DAY	$305	$78	$226	$424	$105	$315
DEOK	$305	$81	$224	$424	$106	$315
DUQ	$305	$80	$224	$424	$112	$315
DOM	$305	$54	$250	$424	$65	$315
EKPC	$305	$76	$229	$424	$103	$315
OVEC	$305	$89	$216	$424	$130	$315
RTO	**$309**	**$49**	**$260**	**$411**	**$55**	**$356**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

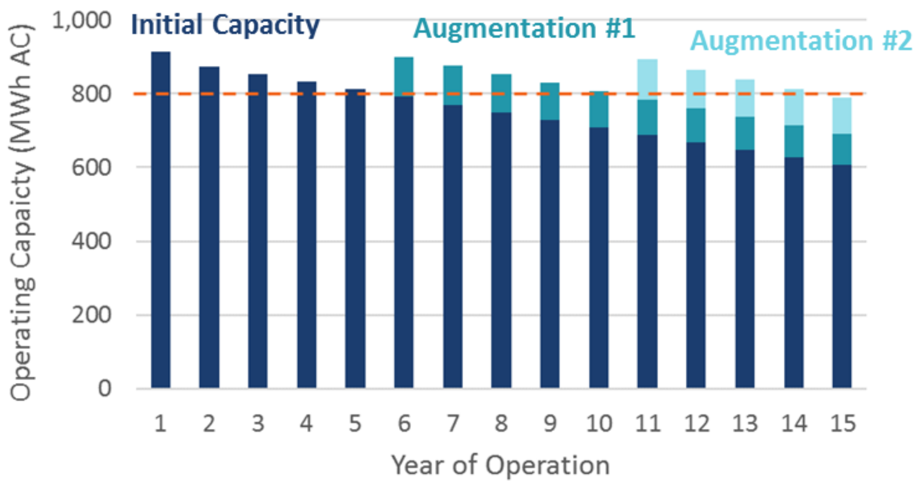
TABLE 29: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
Duration	4 Hours
Installed Energy Capacity	1,030 MWh-dc
Annual Capacity Degradation	4% in Year 1, then 2% per year
Augmentations	Year 5 and Year 10
Use Case	Daily Cycling
Round Trip Efficiency	85%
Economic Life	15 Years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

[42] Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE



Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

Component	Value
Rated AC Output Power (at POI)	**200 MW-ac**
AC Losses	4.6%
Inverter Losses	1.6%
Gross DC Power Output	**212 MW-dc**
Minimum State of Charge	5.0%
Duration	4 hours
Gross Energy Capacity	**895 MWh-dc**
Overbuild due to Degradation	13%, or 135 MWh-dc
Installed Energy Capacity	**1,030 MWh-dc**

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

43 AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

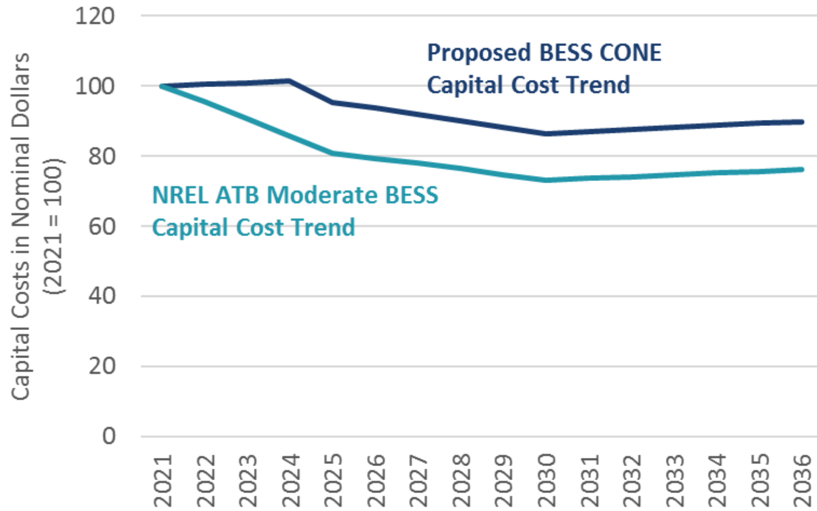
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*200 MW*	*200 MW*	*200 MW*	*200 MW*
EPC Costs				
BESS Equipment				
Batteries and Enclosures	$193.5	$193.5	$193.5	$193.5
PCS and BOP Equipment	$29.0	$29.0	$29.0	$29.0
Project Management	$11.8	$9.4	$10.0	$10.8
Construction & Materials	$58.7	$46.9	$49.6	$53.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included
Total EPC Costs	**$293.0**	**$278.8**	**$282.0**	**$286.9**
Non-EPC Costs				
Project Development	$14.7	$13.9	$14.1	$14.3
Mobilization and Start-Up	$2.9	$2.8	$2.8	$2.9
Owner's Contingency	$11.1	$11.1	$11.1	$11.1
Electrical Interconnection	$4.1	$4.1	$4.1	$4.1
Land	$0.4	$0.3	$0.2	$0.4
Working Capital	$0.0	$0.0	$0.0	$0.0
Financing Fees	$1.3	$1.3	$1.3	$1.3
Total Non-EPC Costs	**$34.6**	**$33.6**	**$33.6**	**$34.1**
Total Capital Costs	**$327.6**	**$312.4**	**$315.7**	**$321.0**
Overnight Capital Costs ($million)	**$328**	**$312**	**$316**	**$321**
Overnight Capital Costs ($/kW)	**$1,638**	**$1,562**	**$1,578**	**$1,605**
Installed Capital Costs ($/kW)	**$1,725**	**$1,646**	**$1,663**	**$1,691**
Installed Capital Costs ($/kWh)	**$409**	**$390**	**$395**	**$401**

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS



V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *200 MW*	2 SWMAAC *200 MW*	3 Rest of RTO *200 MW*	4 WMAAC *200 MW*
Fixed O&M Components				
O&M Contract Fixed Payments	$2.7	$2.7	$2.7	$2.7
BOP and Substation O&M	$0.1	$0.1	$0.1	$0.1
Station Load / Aux Load	$0.4	$0.3	$0.3	$0.4
Miscellaneous Owner Costs	$0.3	$0.2	$0.3	$0.3
Operating Insurance	$1.3	$1.2	$1.3	$1.3
Land Lease or Property Taxes	$2.3	$4.4	$2.1	$2.0
Fixed O&M (2026$ million)	**$7.1**	**$9.0**	**$6.7**	**$6.7**
Fixed O&M ($/kW-yr)	**$35.3**	**$44.8**	**$33.6**	**$33.7**
Augmentation				
Year 5 Costs (2031$ million)	**$30.5**	**$30.5**	**$30.5**	**$30.5**
Year 10 Costs (2036$ million)	**$33.1**	**$33.1**	**$33.1**	**$33.1**
Levelized Augmentation Costs ($/kW-yr)	**$22.3**	**$22.3**	**$22.3**	**$22.3**
Total Levelized Fixed Costs ($/kW-yr)	**$57.7**	**$67.1**	**$55.9**	**$56.1**

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

V.D. CONE Estimates

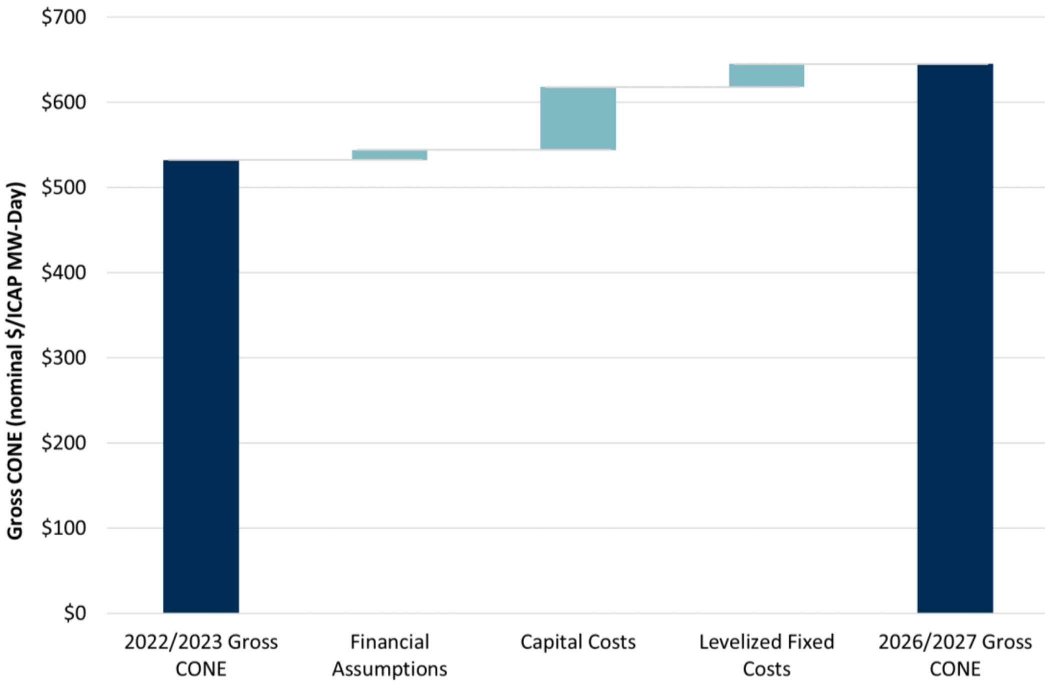
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

			4-Hour Battery Storage			
			EMAAC	SWMAAC	Rest of RTO	WMAAC
	Net Summer ICAP	***MW***	**200**	**200**	**200**	**200**
	Gross Costs					
[1]	Overnight	*$m*	$328	$312	$316	$321
[2]	Installed (inc. IDC)	*$m*	$345	$329	$333	$338
[3]	First Year FOM	*$m/yr*	$7	$9	$7	$7
[4]	Year 5 Augmentation	*$m*	$31	$31	$31	$31
[5]	Year 10 Augmentation	*$m*	$33	$33	$33	$33
	Unitized Costs					
[7]	Overnight	*$/kW*	$1,638	$1,562	$1,578	$1,605
[8]	Installed (inc. IDC)	*$/kW*	$1,725	$1,646	$1,663	$1,691
[9]	Levelized Fixed Costs	*$/kW-yr*	$66	$69	$64	$64
[10]	**After-Tax WACC**	***%***	**7.9%**	**8.0%**	**8.0%**	**8.0%**
[11]	Effective Charge Rate	*%*	11.1%	11.0%	11.1%	11.1%
[12]	**Updated CONE**	***$/MW-yr***	**$247,400**	**$240,900**	**$238,400**	**$241,500**
[13]	**Updated CONE**	***$/MW-day***	**$678**	**$660**	**$653**	**$662**

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

 FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



V.E. Implications for Net CONE

V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	4-Hour BESS Current 2023/24 EAS	4-Hour BESS Removed Regulation	4-Hour BESS Updated 2023/24 EAS
CONE Area 1			
AECO	$414	-$294	$120
DPL	$427	-$285	$142
JCPL	$413	-$295	$118
PECO	$413	-$295	$118
PSEG	$414	-$294	$120
RECO	$419	-$291	$128
CONE Area 2			
BGE	$428	-$267	$161
PEPCO	$423	-$274	$149
CONE Area 4			
METED	$417	-$286	$132
PENELEC	$419	-$290	$128
PPL	$416	-$292	$124
CONE Area 3			
AEP	$418	-$286	$132
APS	$418	-$284	$134
ATSI	$419	-$284	$135
COMED	$425	-$281	$144
DAY	$420	-$281	$139
DEOK	$421	-$280	$141
DUQ	$421	-$283	$139
DOM	$424	-$276	$149
EKPC	$418	-$285	$134
OVEC	$407	-$295	$113
RTO	**$343**	**-$215**	**$128**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	BESS 2026/27 Brattle Estimate CONE	EAS	Net CONE
CONE Area 1			
AECO	$858	$178	$679
DPL	$858	$208	$649
JCPL	$858	$175	$682
PECO	$858	$175	$683
PSEG	$858	$179	$679
RECO	$858	$189	$668
EMAAC	**$858**	**$184**	**$674**
CONE Area 2			
BGE	$875	$234	$641
PEPCO	$875	$219	$656
SWMAAC	**$875**	**$227**	**$648**
CONE Area 4			
METED	$843	$194	$648
PENELEC	$843	$190	$653
PPL	$843	$184	$659
MAAC	**$857**	**$193**	**$663**
CONE Area 3			
AEP	$830	$195	$635
APS	$830	$198	$632
ATSI	$830	$199	$631
COMED	$830	$211	$619
DAY	$830	$204	$625
DEOK	$830	$208	$622
DUQ	$830	$204	$626
DOM	$830	$218	$612
EKPC	$830	$197	$633
OVEC	$830	$168	$662
RTO	**$851**	**$189**	**$662**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

VI. List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
Btu	British Thermal Units
CAISO	California Independent System Operator
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DCP	Dominion Cove Point
DJIA	Dow Jones Industrial Average
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt-Hours
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million

MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NO_x	Nitrogen Oxides
NPV	Net Present Value
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VOC	Volatile Organic Compounds
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Combined-Cycle and Combustion Turbine Cost Details

A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry's many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Turbine Model	PJM Installed Capacity *(MW)*	US Installed Capacity *(MW)*
General Electric 7HA	7,211	12,203
Mitsubishi M501J	3,645	3,645
Siemens SGT6-8000H	1,856	1,856
Mitsubishi M501G	1,444	4,015
General Electric 7F	828	4,130
Siemens SGT6-5000F	755	1,426
General Electric A650	717	717
Siemens SGT6-500	703	703
General Electric 6B.03	276	276
General Electric GRT	210	210
General Electric MS7001	0	1,000
Siemens SGT6-2000	0	232
Siemens SGT6-800	0	224
Solar Turbines Titan 130	0	29
Total	**17,645**	**30,666**
F/G Class Total	3,940	10,485
H/J Class Total	12,712	17,704

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES

Parameter	Unit	CT	CC
Installed Capacity	*MW*	367	1,182
Minimum Stable Level	*MW*	140	176
Ramp Rate	*MW/min*	15	30
Time to Start	*mins*	21	120
Minimum Runtime	*hours*	2	4
NOx Rate	*lb/MMBtu*	0.0093	0.0074
SO2 Rate	*lb/MMBtu*	0.0006	0.0006
Startup Gas Usage	*MMBtu/start*	456	7,988
Startup NOx Emissions	*lb/start*	55	160

A.2 Construction Labor Costs

Labor costs are comprised of “construction labor” associated with the EPC scope of work and “other labor” that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

		EMAAC	SWMAAC	Rest of RTO	WMAAC
1x0 CT Plant					
2021 Construction Labor Hours	*hours*	256,453	239,508	243,744	256,453
2021 Weighted Average Crew Rates	*$*	137.66	118.34	122.59	122.44
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$41,657,600	$31,178,500	$33,466,500	$37,051,400
2021 Construction Labor Costs	*$/kW*	115	86	95	106
Double Train 1x1 CC Plant					
2021 Construction Labor Hours	*hours*	1,809,038	1,687,939	1,718,213	1,809,038
2021 Weighted Average Crew Rates	*$*	143.62	127.97	129.48	129.85
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$306,589,500	$237,598,100	$249,164,300	$277,181,900
2021 Construction Labor Costs	*$/kW*	294	227	244	274

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[45] Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT							
1 Eastern MAAC	178,130	$36.24	$6.46	1,636,480	$3.61	$5.9	-$0.6
2 Southwest MAAC	179,290	$36.24	$6.50	1,647,134	$3.61	$5.9	-$0.6
3 Rest of RTO	173,913	$32.45	$5.64	1,598,262	$3.61	$5.8	$0.1
4 Western MAAC	172,584	$36.24	$6.25	1,586,224	$3.61	$5.7	-$0.5
Gas CC							
1 Eastern MAAC	1,027,945	$36.24	$37.26	6,468,335	$3.61	$23.3	-$13.9
2 Southwest MAAC	1,034,170	$36.24	$37.48	6,509,687	$3.61	$23.5	-$14.0
3 Rest of RTO	1,003,905	$32.45	$32.57	6,316,673	$3.61	$22.8	-$9.8
4 Western MAAC	996,320	$36.24	$36.11	6,269,141	$3.61	$22.6	-$13.5

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

TABLE 40: GAS INTERCONNECTION COSTS

Gas Lateral Project	State	In-Service Year	Pipeline Width (inches)	Pipeline Length (miles)	Pipeline Cost (service year $m)	Pipeline Cost (2021$m)	Pipeline Cost (2021$m/mile)	Meter Station (Y/N)	Station Cost (service year $m)	Station Cost (2021$m)
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y	n.a.	n.a.
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$5.1**			**$4.0**

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

Plant Size	Observations	Electrical Interconnection Cost Capacity Weighted Average	
	(count)	*(2021$m)*	*(2021$/kW)*
< 500 MW	5	$7.2	$18.3
500-750 MW	5	$12.2	$20.7
> 750 MW	7	$23.9	$18.3
Capacity Weighted Average	**17**	**$18.8**	**$18.9**

Source and notes: Confidential project-specific cost data provided by PJM.

A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

TABLE 42: CURRENT LAND ASKING PRICES

CONE Area	**Current Asking Prices**		
	Observations *(count)*	Range *(2022$/acre)*	Land Price *(2022$/acre)*
1 EMAAC	7	$14,430 - $206,620	$96,361
2 SWMAAC	2	$13,148 - $42,785	$29,504
3 RTO	6	$9,867 - $37,429	$16,376
4 WMAAC	6	$22,49 - $68,14	$30,628

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%/yr)*
1 EMAAC								
New Jersey	[1]	4.0%	96.2%	3.8%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.7%	50.0%	1.3%	3.3%
3 RTO								
Ohio	[3]	5.5%	35.0%	1.9%	5.5%	24.0%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	[4]	2.7%	100.0%	2.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.8%	99.0%	3.8%	n/a	n/a	n/a	n/a

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

AUTHORS

J. Michael Hagerty brings experience in evaluating the costs and market value of new and existing generation resources across the U.S. and Canada. He has assisted wholesale market operators, including AESO, PJM, and ISO-NE, in analyzing the availability and costs of new entry of new renewable resources and natural gas power plants for developing key parameters in their markets. These projects included working closely with engineering consultants and stakeholders developing reference resource specifications and bottom-up cost estimates, developing enhanced approaches for calculating E&AS revenues projections, and estimating cost of capital for merchant generation plants. These projects have required extensive engagement with the client and stakeholders to develop well-supported parameters to capacity market demand curve and clearly present our analyses to stakeholders. He has also completed several policy-focused analyses of the future costs of renewable energy resources for U.S. state agencies, including Rhode Island, Nebraska, and Connecticut. Recently, he has assisted a major renewable energy developer in analyzing the value of solar resources in several states for developing community solar compensation mechanisms. Mr. Hagerty also has experience in wholesale market design, transmission planning and development, and strategic planning for utility companies.

Michael.Hagerty@brattle.com

Dr. Samuel A. Newell is an economist and engineer with 23 years of experience consulting to the electricity industry. His expertise is in the design and analysis of wholesale electricity markets and in the evaluation of energy/environmental policies and investments, including in systems with large amounts of variable energy resources. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

Sam. Newell@brattle.com

Johannes P. Pfeifenberger is an economist with a background in electrical engineering and over 25 years of experience in the areas of regulatory economics and finance. He has assisted clients in the formulation of business and regulatory strategy; submitted expert testimony to U.S. and European regulatory agencies, the U.S. Congress, courts, and arbitration panels; and provided support in mediation, arbitration, settlement, and stakeholder processes.

Hannes.Pfeifenberger@brattle.com

Dr. Bin Zhou has over twenty years of consulting experience in consumer goods, energy, financial institutions, pharmaceutical and medical devices, technology, telecommunication, and utilities industries. He specializes in the application of financial economics, management accounting, business organizations, and taxation principles to a variety of consulting and litigation settings.

Dr. Zhou has supported testifying experts and led large engagement teams in many high-profile transfer pricing (Microsoft, Facebook, Coca-Cola, Boston Scientific / Guidant, Eaton, AstraZeneca, and GlaxoSmithKline), bankruptcy (Caesars, U.S. Steel Canada, Nortel, Ambac, and Enron), and securities litigations (MBIA, Parmalat, and Enron). His work has been primarily focused on the economic analysis of transfer pricing disputes involving hard-to-value intangibles, economic substance of complex transactions, solvency analysis and fraudulent conveyance claims, structured finance transactions, financial statement analyses, and damages. His most recent experience also includes economic profit analyses in anti-trust matters, a special litigation committee investigation of a large acquisition in the software industry, two international arbitration cases involving valuation of Korean publicly listed companies, two intellectual property transfers in distressed companies, and cost allocation of mutual fund advisory fees.

Bin.Zhou@brattle.com

Dr. Travis Carless specializes in low-carbon generation, nuclear power, climate policy analysis, and resource planning.

Prior to joining Brattle, Dr. Carless served as a President's Postdoctoral Fellow at Carnegie Mellon University and a Stanton Nuclear Security Fellow at the RAND Corporation. He received an NSF Graduate Research Fellowship for his research, which focused on assessing the environmental competitiveness of small modular reactors (SMRs) and risk and regulatory considerations for SMR emergency planning zones.

Travis.Carless@brattle.com

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_52 Please refer to Section 6.3.4.1 of the IRP.
a. Please confirm whether Kentucky Power modeled any scenarios where the PTC and the ITC do not expire by 2035.
i. If not, please explain why Kentucky Power did not consider an extension of the tax credits beyond 2035.
b. Please explain if Kentucky Power considered that renewable or battery storage projects could qualify for the Energy Community bonus adder.
i. If not, please explain why Kentucky Power did not consider this bonus adder for new renewable and battery storage resources.

RESPONSE

a. For all portfolio modeling, a safe harbor provision is assumed which provides a three-year extension to 2037 of the PTC's and ITC's.

b. Kentucky Power did not consider this as part of the IRP.

b(i). Federal guidance for such qualifications were unclear at the time of modeling, and thus were not taken into account for purposes of the IRP.

Witness: Thomas Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_53 Please refer to Section 6.4 of the IRP.
a. Please provide the load growth assumptions that were used to develop electric vehicle adoption and greater building electrification for the Clean Energy Technology Advancement ("CETA") scenario.
b. Please provide the supporting workbook for Figure 47.
c. Please provide the supporting workbooks for Figure 49, 50, and 51.

RESPONSE

a. The load growth assumptions assumed as part of the CETA Scenario were informed by the Kentucky Power High Load Forecast. As discussed in section 2.13, item 5, while EV growth is expected, it is not forecasted to significantly affect energy sales.

b. Please see KPCO_R_AG_KIUC_1_8_Attachment9 under the tab "Natural Gas Prices."

c. Please see KPCO_R_AG_KIUC_1_8_Attachment9 under the tab "Capital Cost Comparison."

Witness: Thomas Haratym

DATA REQUEST

JI 1_54 Please refer to Section 6.5.2 on page 133 of 1182 of the IRP, where it states, "The ELCC value of the renewables and 4-hour battery storage are based on the amounts installed in each scenario."
a. Please confirm if Kentucky Power modeled the ELCC values shown in Figures 54, 55, and 56 or if the values from Figures 41, 42, and 43 were used in the capacity expansion modeling in AURORA.
i. If the PJM values shown in Figures 41–43 were not used, please explain how Kentucky Power developed the ELCC values from each scenario.
ii. Please provide the supporting workbooks, with all formulas and links intact, that show how Kentucky Power developed the ELCC values.

RESPONSE

a. ELCC values from Figures 41, 42, and 43 were for the Reference scenario, while ELCC from Figures 54, 55, 56 were used for the four other scenarios.

i. The Reference Scenario employed PJM ELCC values (figures 41-43). ELCC values for the other scenarios (figures 54-56) were modified to account for different renewable and storage penetration levels within PJM.

ii. Please see workbook KPCO_R_JI_1_54_Atttachment1.

Witness: Gregory J. Soller

Witness: Thomas Haratym

DATA REQUEST

JI 1_55 Please refer to Section 6.6 of the IRP on page 137 of 1182. Please provide the supporting workbooks for the stochastic gas prices, power prices, and renewable output modeled in AURORA.
a. Please refer to page 150 of 1182 of the IRP, where it says, "This metric is calculated by dividing the winter UCAP of the resource plan by Kentucky Power's winter peak requirement and the summer UCAP of the resource plan by Kentucky Power's summer peak requirement for years 2023-2037 across all five market scenarios. "Please provide the winter UCAP for each of the thermal, solar, wind, battery storage, and energy efficiency resources assumed across the five market scenarios.

RESPONSE

Please refer to KPCO_R_JI_1_55_Attachment1 and KPCO_R_JI_1_55_Attachment2 for the data associated with the stochastic inputs used in this IRP.

a. Please see KPCO_R_KPSC_1_8_Attachment1 for the Capacity Charts and Reserves worksheet.

Witness: Thomas Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_56 Please refer to page 152 of 1182 of the IRP, where it states, "To reflect potential development risk associated with challenges in locating renewables inside Kentucky Power territory, a conservative assumption is made that new wind will not contribute to local impacts, while only 75% of new solar capacity will contribute to this metric."

a. Please explain how Kentucky Power developed the assumption of 75% of capacity for new solar resources.

RESPONSE

The assumption for 75% of new solar resource capacity contributing to the Local Impacts metric was informed through the PJM queue analysis and the potential that competitive RFP responses might come from outside of the Kentucky Power territory.

Witness: Gregory J. Soller

DATA REQUEST

JI 1_57 Please refer to page 155 of 1182 of the IRP, where it states, "The AURORA output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, tax credits, and financial accounting of depreciation, taxes, and utility return on investment."
a. Please provide the AURORA output that was input into the PERFORM model for each of the scenarios modeled in the IRP.
i. If the modeling output from AURORA does not include output from the Resource Table, please provide the Resource Table output for each of the scenarios modeled in the IRP.
b. Please provide the supporting workbooks, with all formulas and links intact, used to develop the annual revenue requirement using the PERFORM model for each of the scenarios modeled in the IRP.

RESPONSE

a. Please see KPCO_R_KPSC_1_8_ConfidentialAttachment10 under the "Aurora Data" tabs.

b. Please see KPCO_R_KPSC_1_8_ConfidentialAttachment7.

Witness: Thomas Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_58 Please refer to Figure 69 on page 156 of 1182 of the IRP.
a. Please confirm if "New DSM" represents energy efficiency and demand response resources or only energy efficiency resources.
b. Please explain if demand response was allowed to be a selectable resource within AURORA.
i. If demand response was not modeled as a selectable resource within AURORA, please explain why not.

RESPONSE

a. New DSM includes only energy efficiency measures. Please see the Company's response to KPSC 1-52b.
b. Demand Response was not included as an alternative DSM resource in this IRP. Please see the Company's response to KPSC 1-52b.

Witness: Thomas Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
Joint Intervenors First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

JI 1_59 Please refer to Figure 79 on page 172 of 1182 of the IRP.
a. Please provide the supporting workbooks, with all formulas and links intact, used to develop the calculations for each of the metrics presented in the portfolio scorecard for each of the portfolios.
b. Please provide the annual carbon emissions for each of the portfolios shown in Figure 79.
c. Please explain how it is possible for AURORA to have optimized the "ECR" portfolio to have an average reserve margin of 3.4% which is less than the 8.9% PJM requirement discussed in Section 3.2 of the IRP.

RESPONSE

a. Please see KPCO_R_KPSC_1_8_Attachment1 and KPCO_R_KPSC_1_8_ConfidentialAttachment10

b. Please see KPCO_R_KPSC_1_8_ConfidentialAttachment10

c. The scorecard displays the average performance of each portfolio against all scenarios. Each portfolio was only optimized under their respective scenario. For example, the ECR portfolio, was only optimized under the ECR scenario, but was tested against all scenarios in the scorecard. Each portfolio when optimized under its own scenario meets PJM's capacity reserve margin obligation for the Company.

Witness: Thomas Haratym

DATA REQUEST

JI 1_60 Please refer to the discussion of the estimated bill impacts of the Preferred Plan on page 179 of 1182 of the IRP.
a. Please provide the supporting workbook, with all formulas and links intact, used to develop the bill impacts for each of the portfolios modeled.

RESPONSE

Please see attachment KPCO_R_KPSC_1_8_Attachment3.

Witness: Gregory J. Soller

DATA REQUEST

JI 1_61 Please refer to Exhibits C-27 and C-28 on page 216 of 1182 of the IRP.
a. Please provide the supporting workbooks, with all formulas and links intact, used to develop Exhibits C-27 and C-28.
b. Please confirm that the electric vehicle adoption and distributed generation forecasts are included within the load forecast modeled in AURORA.
c. Please explain how Kentucky Power developed the Electric Vehicle forecast.
d. Please explain if the Inflation Reduction Act tax incentives were factored into the Electric Vehicle forecast.
e. Please explain how Kentucky Power developed the distributed energy resources forecast.
f. Please provide the units for the "Distributed Energy Resource" and "Capacity" column shown in Exhibit C-28.
g. Please explain if the Inflation Reduction Act tax incentives were factored into the distributed energy resources forecast.
h. Figure 9 (page 41 of 1182) shows a significant increase in DER between 2020 and 2021. Please explain why the forecast from 2022 forward is linear and a much smaller rate of increase than seen between years 2020 and 2021

RESPONSE

a. See KPCO_R_JI_1_61_Attachment1 and KPCO_R_JI_1_61_Attachment2 for the requested information.

b. Electric vehicle adoption and distributed generation trends are implicitly included in the load forecast modeled in AURORA.

c. The electric vehicle (EV) forecast is developed using a consensus approach. EV stock forecasts from the US Energy Information Administration (EIA), International Energy Administration (IEA), OPEC, ExxonMobil, BP, and Bloomberg New Energy Finance were weighted to develop the consensus. The growth rates derived from this consensus are then applied to the latest historical EV registration data and the forecast is developed. The historical EV registration data are currently sourced from EPRI at the zip code+4 level.

d. The Inflation Reduction Act had not been enacted at the time the Company's load forecast was developed. Impacts of the Inflation Reduction Act were not factored into the EV forecast.

e. The solar photovoltaic (PV) forecast is based off of the US Energy Information Administration (EIA) Annual Energy Outlook (AEO) forecast. Growth rates from the most recent AEO are applied to historical, company PV interconnection data.

f. Distributed energy resource is the number of distributed generation units and capacity is in kilowatts.

g. The inflation Reduction Act had not been enacted at the time the Company's load forecast was developed. Impacts of the Inflation Reduction Act were not factored into the Distributed Energy Resource forecast.

h. The 2021 change was perceived as a short-term growth, rather than a change in long-term trends.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_62 Please refer to the “Key Supply-Side Resource Option Assumption” on page 218 of 1182 of the IRP.
a. Please provide the supporting workbook, with all formulas and links intact, used to develop the levelized cost of energy (“LCOE”) for each of the new generation technologies shown in the table.
b. Please explain the discrepancy between the “Installed cost” numbers shown in this table and the capital cost assumptions shown in Figure 18, 20, and 22 for battery storage, wind, and solar resources.

RESPONSE

a. Please see KPCO_R_JI_1_62_Attachment1

b. Appendix Exhibit D is in Real 2021 dollars (no inflation assumption included). Figures 18, 20, and 22 are in Nominal dollars (assumed Producer Price Index applied).

Witness: Thomas Haratym

DATA REQUEST

JI 1_63 Please refer to Exhibit E1 on pages 219–223 of 1182 of the IRP.
a. For each of the scenarios, please provide the energy efficiency bundles that were selected in the AURORA capacity expansion optimization.
b. Please explain if the Big Sandy extension was hardcoded into the model or if AURORA was allowed to optimize the decision on whether to extend operations at the Big Sandy unit.
c. Please identify any additional operation and maintenance costs or capital expenditures needed for the Big Sandy unit to extend operations until 2041. Please explain in detail the nature and amount of any such costs and their anticipated timing.
ii. If there are additional costs, please provide the costs that were included in the AURORA model for the Big Sandy extension.
d. Please explain if Kentucky Power evaluated any modeling runs where the level of capacity purchases in 2028 is set to a value lower than the 500 MW limit.

RESPONSE

a. Please see KPCO_R_JI_1_63_Attachment1.

b. The continued operation of Big Sandy Unit 1 was made as an available resource for optimized selection within the Aurora model.

c. Please refer to response KPSC_1_19

d. No.

Witness: Thomas Haratym

DATA REQUEST

JI 1_64 Please refer to Exhibit E-2 on pages 225–304 of 1182 of the IRP. Please provide all modeling results presented in Exhibit E-2 in machine readable format, with all formulas and links intact.

RESPONSE

Please see KPCO_R_KPSC_1_8_ConfidentialAttachment7.

Witness: Thomas Haratym

Kentucky Power Company
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DATA REQUEST

JI 1_65 For the Big Sandy and Mitchell plants, please provide the following historical annual data by unit, or, if Kentucky Power does not maintain unit- level data, by plant, from 2015 to present:
a. Fixed O&M cost;
b. Variable O&M cost;
c. Fuel Costs;
d. Capital expenditures;
e. Heat rate;
f. Generation;
g. Capacity factor;
h. Forced outage rate;
i. Planned outage rate;
j. Energy revenues;
k. Capacity revenues.

RESPONSE

The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. The Company did not use any historical data to develop the IRP Report. Without waiving these objections, the information requested in subparts a through d and subpart f is publicly available in the Company's FERC Form 1.

Witness: Brian K. West

Witness: Thomas Haratym

Kentucky Power Company
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Dated May 22, 2023

DATA REQUEST

JI 1_66 For the Big Sandy and Mitchell plants, please provide the following projected data by unit for the planning period modeled for this IRP:
a. Fixed O&M cost;
b. Variable O&M cost;
c. Capital expenditures;
d. Forced outage rate.

RESPONSE

Please see KPCO_R_JI_1_66_ConfidentialAttachment1.

Witness: Thomas Haratym

Kentucky Power Company
KPSC Case No. 2023-00092
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Dated May 22, 2023

DATA REQUEST

JI 1_67 In comparing and evaluating possible supply-side and demand-side resource additions (including distributed generation) does the Company consider the costs of pollutants and environmental damage, negative health impacts, and the potential avoided costs of these?[13]? If yes, please explain in detail how they are considered. If no, please explain in detail why not.

[13] *See e.g.*, the costs quantified in: EPA, *Public Health Benefits-per-kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report* (May 2021), https://www.epa.gov/sites/default/files/2021-05/documents/bpk_report_second_edition.pdf ; and Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (Feb. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxid e.pdf)

RESPONSE

All resources considered comply with known rules and regulations, and include the effect of a potential carbon burden. The indirect costs and externalities listed in the question were not included in this IRP. There is significant uncertainty around scale and timing of these indirect costs.

Please see the response to KPSC 1_13 for a description on the estimated direct avoided T&D costs that were included.

Witness: Jeffrey Huber

Witness: Gregory J. Soller

DATA REQUEST

JI 1_68 How did the Company include consideration of weather extremes into the IRP planning process, if at all? Do the Company's forecasts and planning take account of the risk of more extreme weather in the future, as is expected due to climate change, and as we have already been experiencing in recent years? Please explain in full.

RESPONSE

For this IRP, the Company did not consider a specific extreme weather event. The Clean Energy Technology Advancement (CETA) Portfolio was optimized to the Company's high load forecast, as discussed in section 7.3.1 (page 157 of 1182). The Company's high load forecast encapsulates potential extreme weather summer and winter demands.

Witness: Glenn R. Newman

Witness: Gregory J. Soller

DATA REQUEST

JI 1_69 In the Commission's May 14, 2021 Order in Case No. 2020-00174[14], the Commission identified several principles that Kentucky Power should follow in evaluating distributed generation. These include: evaluating eligible generating facilities as a utility system or supply side resource; Treating benefits and costs symmetrically; conducting forward-looking longer term and incremental analyses; avoiding double counting; and ensuring transparency. Please indicate:

a. How the Company has followed these principles when planning for the role of distributed generation in the planning period.

b. What avoided costs have been incorporated into the analyses of distributed generation? For example, have any of the following been included: avoided energy cost, ancillary services cost, generation capacity cost, transmission capacity cost, distribution capacity cost, carbon cost, environmental compliance cost?

c. How the Company has applied any of these same principles and avoided costs to evaluation of any of its DSM (including energy efficiency) programs?

d. Has the Company considered jobs benefits of distributed generation or energy efficiency programs? Please explain in full.

[14] Order, In re Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief, Case No. 2020-00174, at 21–23 (May 14, 2021).

RESPONSE

a and b. As discussed in section 2.6.1, distributed generation was assumed as a load modifier to the Company's load forecast. The Company did not model a distributed generation resource as an alternative for optimized selection in this IRP.

c. The Company modeled energy efficiency programs as a supply-side resource for optimal selection against all other available resources. This is further discussed in section 4 of the IRP.

d. For this IRP, a specific jobs benefit related to distributed generation was not evaluated.

Witness: Gregory J. Soller

Witness: Thomas Haratym

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DATA REQUEST

JI 1_70 The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM-DER ")[15] provides a comprehensive framework for cost-effectiveness assessment of distributed energy resources including distributed generation, distributed storage, demand response, and energy efficiency. The NSPM-DER also provides guidance on addressing multiple DERs and rate impacts and cost shifts. In their order in the Kentucky Power Company Case No. 2020-00174, concerning net metering, the Commission adopted a series of principles to be used when establishing new net metering rates. These principles are consistent with those presented in the NSPM-DER and are applicable to evaluating the benefits and costs of all DER's, in addition to net metering.
a. Is the Company aware of and familiar with the NSPM-DER?
b. Has the Company utilized the NSPM-DER within the IRP process for evaluating DSM, energy efficiency, and distributed generation resources? Please explain in full.

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

RESPONSE

a. The Company has not reviewed the referenced report.

b. No, for this IRP, the Company did model energy efficiency programs as an equivalent supply-side resource as discussed in section 4 of the IRP.

Witness: Gregory J. Soller

Witness: Thomas Haratym

DATA REQUEST

JI 1_71 Please provide any internal analysis and discussion materials used to forecast and consider the impact of the proposed Integrated Resource Plan (IRP) on low-income customers at 30%, 50%, and 80% Area Median Income ("AMI"), if any.

RESPONSE

As part of this IRP, no studies or analyses were conducted relating to low-income customers separately because the plan looks at customer affordability across all customer classes.

Witness: Brian K. West

DATA REQUEST

JI 1_72 Please provide the historical data on low-income households considered in the preparation of the Integrated Resource Plan, if any, by census tract and zip code. If the requested data is unavailable at the requested scale, please provide the data in the most granular geographic scale available.

RESPONSE

The load forecast used in this IRP did not evaluate load below the sector level. All residential customers and load are modeled in total.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_73 Please provide any internal analysis of Annual Use-per-Customer and Total Energy Sales correlated to impact on average customer bills as 30%, 50%, and 80% Area Median Income ("AMI"). Please provide data by census tract and zip code. If the requested data is unavailable at the requested scale, please provide the data in the most granular geographic scale available.

RESPONSE

The Company has not performed the requested analysis.

Witness: Glenn R. Newman

DATA REQUEST

JI 1_74 Please provide any analysis performed by the Company specifically concerning future low-income household customer demand for energy, if any. Please provide the data considered as a part of this process by census tract and zip code. If the requested data is unavailable at the requested scale, please provide the data in the most granular geographic scale available.

RESPONSE

The Company has not performed the requested analysis.

Witness: Glenn R. Newman

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DATA REQUEST

JI 1_75 Please provide studies related to environmental and health impacts on low-income communities and communities of color considered as a part of the IRP process, if any, including any internal analysis and discussion materials from the Company of these studies.

RESPONSE

The new resources identified in the IRP generic are not location specific. The IRP also does not take into account specific demographic characteristics. Therefore, no such studies were prepared or considered as part of this IRP.

Witness: Thomas Haratym

Kentucky Power Company
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Dated May 22, 2023

DATA REQUEST

JI 1_76 Please provide, if any, studies related to the impact of economic disparities on low-income communities and communities of color considered as a part of the IRP process, including any internal analysis and discussion materials from the Company of these studies.

RESPONSE

Please see the Company's response to JI 1_75.

Witness: Brian K. West

Witness: Thomas Haratym

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DATA REQUEST

JI 1_77 Please provide the energy burden analysis considered as a part of the IRP process, if any, including any internal analysis and discussion materials from the Company of such analyses.

RESPONSE

The Company is not familiar with the reference to an "energy burden analysis". To the extent the question is referring to the Company's ability to serving the energy load to Kentucky customers, the IRP modeling incorporates energy production requirements to serve customer load. This is illustrated in the IRP scorecard broken down by technology as shown in Figure 82 on page 176 of 1182 in IRP.

Witness: Thomas Haratym

DATA REQUEST

JI 1_78 Please provide data on the impact of electrifying large sectors of the U.S. economy over the period of the proposed IRP and the implications for low- income customer affordability and access. What steps is the Company taking to ensure equitable distribution of benefits and costs on low-income customers? Please provide any and all analysis. Please provide data by census tract and zip code.

RESPONSE

The Company objects to this request to the extent it seeks information that is not relevant to these proceedings nor reasonably calculated to lead to the discovery of admissible evidence. Cost causation and rate design is appropriate within the context of a base rate case proceeding, not an IRP.

Without waiving this objection, the Company states as follows: the load forecast used to prepare the IRP does not include a separate analysis for the scenario described in the question. The IRP does not include customer locational specific analysis. Also see the Company's response to JI 1_71.

Witness: Glenn R. Newman

Witness: Brian K. West

Kentucky Power Company
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DATA REQUEST

JI 1_79 Please provide the following data, and any and all internal analysis and discussion materials, on how this influenced the preparation of the IRP and how COVID-19 pandemic data impacted the analysis in anticipating future pandemic instability:

a. Please provide data for the number of people who are eligible for electric disconnection by census tract.
b. Please provide data on the number of people who are behind on their electric payments by census tract.
c. Please provide data on the average amount owed on past due bills by census tract.
d. Please provide data on the number of people who have a signed repayment plan by census tract.
e. Please provide data on the number of people who are behind on their payments, but do not have a signed payment plan in place by census tract.
f. Please provide data on the number of people who have a signed payment plan who are current on that payment plan by census tract.
g. Please provide data on the number of people who have a signed payment plan who have missed one or more payments by census tract.
h. Are the people who have missed one or more payments on their payment plan included in the overall number of people who are eligible for disconnection? Please explain.
i. Please provide data on the number of people who have received support from pandemic utility assistance programs by census tract.
j. Please provide data on the amount of money received by the Company from pandemic utility assistance programs.

Note: if data requested above is unavailable at the census tract level, please provide data at the most granular geographic scale available.

RESPONSE

The Company objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence.

Witness: Counsel

DATA REQUEST

JI 1_80 In their 2017 report "Lights Out in the Cold: Reforming Utility Shut-Off Policies as If Human Rights Matter," the NAACP "calls for concrete action toward establishing policies that protect the well-being of all utility customers and the eventual elimination of utility disconnections."16 They also provide "a collection of true stories about real people whose lives were cut short, or nearly cut short, by utility companies who were willing to pull the plug to protect profits,"17 and go on to state that "the establishment of a universal right to uninterrupted energy service would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages."18 Specific to Kentucky electric utilities, the Commission's regulations establish certain circumstances under which an electric utility shall not terminate service for non-payment, 807 KAR 5:006(15)(2)-(3), and provide for winter hardship reconnection, 807 KAR 5:006(16).

a. Please explain what concrete action(s) the Company is taking to ensure and increase universal access to electricity, especially to underserved communities such as low-income households and communities of color?

b. What policies do you have in place that go above and beyond the legal rights codified in 807 KAR 5:006, if any?

16 Marcus Franklin et al., *Lights Out in the Cold: Reforming Utility Shut-Off Policies as If Human Rights Matte*r, NAACP, at iii (Mar. 2017), https://naacp.org/resources/lights-out-cold.

17 *Id.* at 3–5.

18 *Id.* at iv.

RESPONSE

The Company objects to the request to the extent it calls for legal analysis or opinions, which are not the appropriate subject of discovery. The Company further objects to the question to the extent it seeks information that is not relevant to these proceedings nor reasonably calculated to the discovery of admissible evidence. Without waiving these objections, the Company states as follows:

a. The Company has an obligation to serve all customers regardless of their socio-economic status. Nonetheless, Kentucky Power recognizes the financial hardships that some customers are experiencing and wants to work with customers to ensure that they can pay their bills. Examples of the Company's willingness to work with customers include payment extensions, payment arrangements, and two types of budget billing.

Additionally, Kentucky Power has two home energy assistance programs (HEART and THAW). HEART (Home Energy Assistance in Reduced Temperatures) is designed to assist low-income residential customers. THAW (Temporary Heating Assistance in Winter) is designed to help customers who do not require the broader and more sustained help provided by HEART, but who nonetheless are at risk of losing their electric service because of a temporary situation. Both programs are offered during the winter heating months of January through April when customers typically have higher electric bills. There is a demonstrable need, due to the number of applications received, for both programs. Accordingly, the Company will soon propose as part of its upcoming base rate case to increase contributions to the programs so that more customers can receive assistance from these programs.

In regards to home energy efficiency the Company's TEE (Targeted Energy Efficiency) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by the local community action agency. This program provides energy saving improvements to an existing home. Program services include residential energy audits, the installation of home weatherization/energy conservation items and customer education on home energy efficiency.

b. Kentucky Power exceeds certain regulation requirements in a number of ways, including the following:

- Service on residential accounts will not be disconnected without personal contact first made with an adult member of the household during extreme temperatures (32° Fahrenheit or below or 92° Fahrenheit and above).

- Relaxed winter credit policies during December 1 – March 31 that allows residential customers to establish one extended payment arrangement, even if the account would not normally qualify. For this extended payment arrangement, the initial payment amount can be 1/2 to 1/6 of the arrears. For example, a past due balance of $200 would require an initial payment between $33 and $100. If the account is already on an extended payment arrangement, Kentucky Power will renegotiate once.

- An account can be set up on the Average Monthly Payment (AMP) plan to begin the next month when an extended payment arrangement is established.

- The Company's AMP program is distinct from the Equal Payment Plan (Budget) required by 807 KAR 5:006 Section 14(2)(a). With AMP, customers can minimize large seasonal variations in electric service billings by paying an average amount each month. This differs from Budget, which can have a large settle-up at the end of the year. Customers on fixed incomes or with budgeted finances especially benefit through the more consistent payment of AMP.

- Streamlined procedure for processing of medical certificate forms. This process allows for the form to be faxed to the physician's office with the required information clearly identified. This process has resulted in fewer incomplete forms being received and thus limited the potential for accounts to be at risk for disconnection.

- 807 KAR 5:006, Section 15(1)(f)(1)(b) states "*Service shall not, for any reason, be terminated before twenty-seven (27) days after the mailing date of the original unpaid bill."* Typically, Kentucky Power's residential customers are not subject to disconnection for approximately 40 days or longer. For illustration, say a residential customer is issued a bill on January 1 and becomes past due on this balance. The disconnect notice will not be issued until the day after their next meter reading date (which would be approximately 30 days after the January 1 bill was issued). That disconnect notice would provide the 10 days' notice required by regulation. Thus, the residential customer in this example would not be subject to disconnection for at least approximately 40 days after the January 1 bill was issued.

Witness: Brian K. West

DATA REQUEST

JI 1_81 Please provide data on charges and disbursements (incentives, rebates, and/or weatherization assistance) for the Targeted Energy Efficiency program, by census tract or zip code.

RESPONSE

Kentucky Power maintains the information by zip code. Please see KPCO_R_JI_1_81_Attachment1 for the requested information for the 2020, 2021 and 2022 calendar years. Please note that the total amount for the information provided will not match the amounts filed with annual Demand-Side Management filings. The reason for the discrepancy is due to the 2022 DSM filing reported information through September 2022. The second reason is due to the participant information being recorded in the month the work is completed and the expense information being tracked when the invoice is paid.

Witness: Brian K. West

Zip Code	Air Leakage /Duct Work	Insulation	Heating System Replacement	Water Heater	Lighting	Education Material	Administration Fee	Total
40868	$ 496.22	$ 5,003.67	$ 10,400.00			$ 200.00	$ 800.00	$ 16,899.89
41101	$ 2,429.76	$ 1,776.17	$ 7,800.00	$ 112.50	$ 37.50	$ 250.00	$ 600.00	$ 13,005.93
41102	$ 5,671.31	$ 5,564.26	$ 13,000.00	$ 2.51		$ 400.00	$ 1,600.00	$ 26,238.08
41121	$ 411.19	$ 963.38	$ 2,600.00			$ 50.00	$ 200.00	$ 4,224.57
41129	$ 1,183.34	$ 1,050.55	$ 2,600.00			$ 100.00	$ 400.00	$ 5,333.89
41132	$ 534.75	$ 961.75	$ 2,600.00			$ 50.00	$ 200.00	$ 4,346.50
41139	$ 2,467.07	$ 3,722.97	$ 10,400.00	$ 57.00	$ 28.50	$ 200.00	$ 800.00	$ 17,675.54
41143	$ 5,347.70	$ 5,812.67	$ 23,400.00	$ 75.00		$ 550.00	$ 2,000.00	$ 37,185.37
41144	$ 2,977.63	$ 4,107.47	$ 13,000.00			$ 250.00	$ 1,000.00	$ 21,335.10
41146	$ 171.18	$ 1,379.85	$ 2,600.00			$ 50.00	$ 200.00	$ 4,401.03
41164	$ 15,810.47	$ 13,555.24	$ 70,200.00	$ 138.50	$ 57.84	$ 1,500.00	$ 5,800.00	$ 107,062.05
41180	$ 2,256.40	$ 16.22	$ 5,200.00			$ 100.00	$ 400.00	$ 7,972.62
41222	$ 721.40	$ 273.00	$ 62.12	$ 100.00		$ 50.00	$ 200.00	$ 1,406.52
41224	$ -	$ 1,698.20	$ 4,142.18	$ 251.41		$ 100.00	$ 400.00	$ 6,591.79
41230	$ 1,464.71	$ 987.31	$ 2,600.00	$ 1.50		$ 100.00	$ 400.00	$ 5,553.52
41231	$ -	$ -	$ 2,229.27	$ 94.14		$ 50.00	$ 200.00	$ 2,573.41
41234	$ -	$ 2,085.44	$ 2,296.20			$ 50.00	$ 200.00	$ 4,631.64
41238	$ -	$ -	$ 2,395.05	$ 166.83		$ 50.00	$ 200.00	$ 2,811.88
41501	$ 1,329.58	$ 4,503.28	$ 26,772.75	$ 892.69	$ 3.54	$ 600.00	$ 2,400.00	$ 36,501.84
41514	$ -	$ 896.78	$ 2,585.44	$ 138.93		$ 50.00	$ 200.00	$ 3,871.15
41522	$ 643.76	$ -	$ 4,826.32	$ 111.94		$ 100.00	$ 400.00	$ 6,082.02
41537	$ -	$ 2,803.23	$ 2,600.00			$ 50.00	$ 200.00	$ 5,653.23
41544	$ -	$ -	$ 2,222.14	$ 169.71		$ 50.00	$ 200.00	$ 2,641.85
41562	$ -	$ 2,704.96	$ 2,078.01	$ 45.68		$ 50.00	$ 200.00	$ 5,078.65
41616	$ -	$ 320.50	$ 2,454.96	$ 34.93		$ 50.00	$ 200.00	$ 3,060.39
41631	$ -	$ -	$ 2,553.87	$ 52.36		$ 50.00	$ 200.00	$ 2,856.23
41635	$ 304.38	$ 2,143.99		$ 200.47		$ 50.00	$ 200.00	$ 2,898.84
41663	$ -	$ 1,683.65	$ 7,337.21	$ 321.48		$ 150.00	$ 600.00	$ 10,092.34
41701	$ 1,367.15	$ 20,985.29	$ 33,530.16			$ 750.00	$ 3,000.00	$ 59,632.60
41713	$ -	$ 1,826.93	$ 2,600.00			$ 50.00	$ 200.00	$ 4,676.93

Zip Code	Air Leakage /Duct Work	Insulation	Heating System Replacement	Water Heater	Lighting	Education Material	Administration Fee	Total
41714	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41719	$ -	$ 1,327.37	$ 10,400.00			$ 200.00	$ 800.00	$ 12,727.37
41721	$ 381.09	$ 4,069.74	$ 7,800.00			$ 250.00	$ 1,000.00	$ 13,500.83
41723	$ -	$ -	$ 5,200.00			$ 100.00	$ 400.00	$ 5,700.00
41731	$ -	$ -	$ 2,583.50			$ 50.00	$ 200.00	$ 2,833.50
41740	$ -	$ 6,852.98	$ 2,600.00			$ 100.00	$ 400.00	$ 9,952.98
41745	$ -	$ -	$ 5,200.00			$ 100.00	$ 400.00	$ 5,700.00
41749	$ 1,012.98	$ 10,623.44	$ 18,200.00	$ 26.50		$ 400.00	$ 1,600.00	$ 31,862.92
41759	$ 315.18	$ 2,492.23	$ 2,600.00			$ 50.00	$ 200.00	$ 5,657.41
41763	$ 483.56	$ 4,708.32	$ 2,600.00	$ 38.24		$ 150.00	$ 600.00	$ 8,580.12
41764	$ 755.74	$ 4,250.21	$ 5,200.00			$ 150.00	$ 600.00	$ 10,955.95
41772	$ 1,195.08	$ 2,171.12	$ 2,600.00	$ 1.69		$ 50.00	$ 200.00	$ 6,217.89
41773	$ -	$ 2,890.53	$ 15,600.00			$ 300.00	$ 1,200.00	$ 19,990.53
41774	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41776	$ -	$ 12,854.64	$ 18,200.00			$ 350.00	$ 1,400.00	$ 32,804.64
41804	$ -	$ 1,640.89	$ 5,800.00			$ 150.00	$ 600.00	$ 8,190.89
41812	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41815	$ -	$ -	$ 2,591.78			$ 50.00	$ 200.00	$ 2,841.78
41822	$ 859.53	$ 1,580.01	$ 13,000.00	$ 12.15	$ 17.36	$ 250.00	$ 1,000.00	$ 16,719.05
41824	$ -	$ 2,803.49	$ 2,600.00			$ 50.00	$ 200.00	$ 5,653.49
41826	$ -	$ 1,110.72	$ 5,200.00			$ 150.00	$ 600.00	$ 7,060.72
41832	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41835	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41836	$ -	$ 1,233.58	$ 2,600.00			$ 50.00	$ 200.00	$ 4,083.58
41843	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41844	$ -	$ -	$ 2,600.00			$ 50.00	$ 200.00	$ 2,850.00
41855	$ -	$ 2,773.46	$ 5,200.00			$ 100.00	$ 400.00	$ 8,473.46
41858	$ 766.34	$ 4,597.24	$ 10,400.00		$ 28.02	$ 300.00	$ 1,200.00	$ 17,291.60
Grand Total	**$ 51,357.50**	**$ 154,806.73**	**$ 431,460.96**	**$ 3,046.16**	**$ 172.76**	**$ 9,800.00**	**$ 38,400.00**	**$ 689,044.11**

DATA REQUEST

JI 1_82 How has the Company engaged stakeholders, including residential customers, in the development of this IRP?
a. Please provide copies of all materials shared with stakeholders at any stakeholder meetings held concerning the IRP.
b. Please provide copies of any comments submitted to the Company by stakeholders during the IRP development process.

RESPONSE

The Company held two technical conferences with stakeholders during the development of the IRP. The first was held on July 14, 2022, and the second was held on January 25, 2023. In its 2019 IRP, Case No. 2019-00443, Kentucky Power also held technical conferences and was the first investor-owned utility in the Commonwealth to do so even though meetings of this type are not required by the regulations governing IRP filings.

a. See KPCO_R_JI_1_82_Attachment1 for the requested information.

b. See KPCO_R_JI_1_82_Attachment2 for the requested information.

Witness: Brian K. West

Kentucky Power 2022 IRP

IRP Stakeholder Meeting Material

July 14th, 2022

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Agenda

- Welcome and Introductions
- Overview of the 2022 IRP Process
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Microsoft Teams meeting
Join on your computer or mobile app
Click here to join the meeting
Or join by entering a meeting ID
Meeting ID: 211 148 903 214
Passcode: 5sqrXd
Join with a video conferencing device
953812256@t.plcm.vc
Video Conference ID: 118 639 713 2
Alternate VTC instructions
Or call in (audio only)
+1 614-706-7239,,703867959# United States, Columbus
Phone Conference ID: 703 867 959#
Find a local number | Reset PIN
Learn More |

Stakeholder feedback is encouraged throughout the presentation.

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Housekeeping

COVID-19 Protocols (In Person Attendance)

- We encourage appropriate precautions.
- Facemasks are not required at this time, though please wear if you prefer.
- Social distancing is recommended.
- Frequent hand washing and hand sanitizer use.

Housekeeping (Virtual Attendance)

- Microsoft Teams Meeting will be active during event.
- Please mute your audio unless speaking.
- Stakeholder feedback is encouraged throughout the presentation.
- Chat window will be monitored.

Safety Topic

Speaker: David Swain – Liberty Utilities President, Southern Region

Company Overview - Who we Are

Headquartered in Ashland, Ky., Kentucky Power is one of seven operating companies owned by American Electric Power, which has a combined service territory spanning 11 states across America's heartland.

We provide service to approximately 165,000 retail customers in all or part of 20 eastern Kentucky counties. Kentucky Power’s distribution operations work from service centers in Ashland, Hazard and Pikeville and from area offices in Paintsville and Whitesburg.

We are an electric company that believes the power to make a difference is in all our hands. When you connect with our service, you tap into a community resource that sustains life, achieves technological innovation and spurs economic growth. Together, with you, we create brighter futures and boundless opportunities in 20 counties on the eastern edge of the Bluegrass State.

Our connection to our community runs deep, and we continue to strengthen it by investing in issues that matter most to you and your family.

KENTUCKY POWER

Company Overview

Service Territory & Generation Resources

Key Facts

2021 Energy Sales	5,980	GWh
Avg. Annual Use per Residential Customer	14,791	kWh
Avg. Cost per kWh for Residential Customers	14.24	¢/kWh
Distribution Lines	10,051	miles
Transmission Lines	1,217	miles
Owned Generation	1,075	MW
Generation under Unit Power Agreement	393	MW
2021 Total Customer Count		
Residential	133,805	
Commercial	30,532	
Industrial	1,079	
Combined Rate Base as of 12/31/2021	~2.0 billion	$
KPCo Senior Unsecured Credit Rating	Baa3 / BBB+	

Note: The Rockport UPA for 393 MW expires on 12/7/22. On 12/31/28, Kentucky Power will no longer have an interest in the Mitchell Plant.

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KENTUCKY POWER

About CRA

CRA International

- 780 Consultants
- 23 Offices in 9 Countries
- 15 Practice Areas
- Founded in 1965

Energy Practice Offices

Boston
New York
Washington DC
Toronto
London
Munich

Energy Practice Offerings

Corporate Strategy

Corporate Scenario Development & Analytics

Portfolio Optimization

Offering Development

M&A / Growth Strategy

Market Entry Strategy

Resource Strategy & Investment Planning

Integrated Resource Plan

Grid Modernization

Utility of the Future

Infrastructure Planning

Storage Assessments

Rate Impact Analysis

Market Analysis & Design

Power and Gas Market Forecasts

Market Based Rate (MBR) filings

FERC Analysis (Order 841, Order 1000)

Capacity Market Design

RTO Cost Benefit Analysis

Transaction & Restructuring Support

Energy Assets Due Diligence and Valuation

Company Restructuring

Competitive Merger Reviews

Utility M&A Due Diligence

Regulatory and Litigation Support

FERC and State Ratemaking

Damages Analysis

International Arbitration

Commercial Litigation

Expert Testimony

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Resource Planning Work for Utilities

CRA has supported many IOUs and POUs with strategy and investment planning.

Client examples from the last 3 years

NiSource

- 2018, 2021 IRP
- Responsibility for inputs development, modeling, stakeholder engagement
- Regulatory testimony in rate case and CPCN proceeding
- Also led energy procurement

Dominion Energy

- Dominion South Carolina 2020, 2021, 2022 IRP
- Responsibility for process validation and stakeholder engagement
- Regulatory testimony development

American Electric Power

- Supported 2021 IRP development for SWEPCO and PSO
- Responsibility for inputs development, market and portfolio modeling, drafting of IRP reports and stakeholder materials

Alliant Energy

- 2019-2021 Clean Energy Blueprint and IRP development for WI and IA
- Responsibility for inputs development, modeling, stakeholder engagement
- Regulatory testimony in rate case and CPCN proceeding

Liberty

- Developed 2019 IRP for Empire District
- Responsibility for analyzing resource options and evaluating generation portfolios
- Oversaw stakeholder engagement activities and presentation of IRP analysis

Minnkota Power Cooperative

- 2021 resource plan
- Responsibility for inputs development, modeling, Board engagement
- Company is evaluating carbon capture and sequestration

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Questions?

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IRP Purpose

The purpose of the IRP

- Provide a roadmap at a point in time that utilities and load serving entities use as a planning tool when evaluating resource decisions necessary to meet forecasted electric capacity and energy demand requirements in a balanced approach.

Requirements

- Meets the requirements of 807 KAR 5:058 and Kentucky Public Service Commission (KPSC or Commission) Staff recommendations provided in the Staff Report on Kentucky Power's 2019 Integrated Resource Plan.

- An IRP is conducted every 3 years, evaluating resource needs over a 15-year planning period.

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Review of the 2022 IRP Process, Roles, and Responsibilities

Overview of 2022 IRP Responsibilities

KY Power
- Sets Objectives & Performance Criteria
- Provides Load and Demand-side Assumptions
- Manages Regulatory Process

CRA
- Develops Supply-side Assumptions
- Develops Market Scenarios & Inputs
- Develops Candidate Resource Portfolios
- Populates Scorecard

KY Power
- Evaluates Resource Alternatives
- Selects Preferred Plan for 2022 IRP
- Develops Short-term Action Plan

2022 IRP Analysis Steps

Define IRP Objectives Aligned to Customer Needs

⇩

Model Market Scenarios to Test Future Risks

⇩

Develop Candidate Portfolios of Demand and Supply Side Resources

⇩

Test Portfolios across Scenarios & Stochastic Risks

⇩

Compare Results on the Scorecard & Select the Preferred Plan

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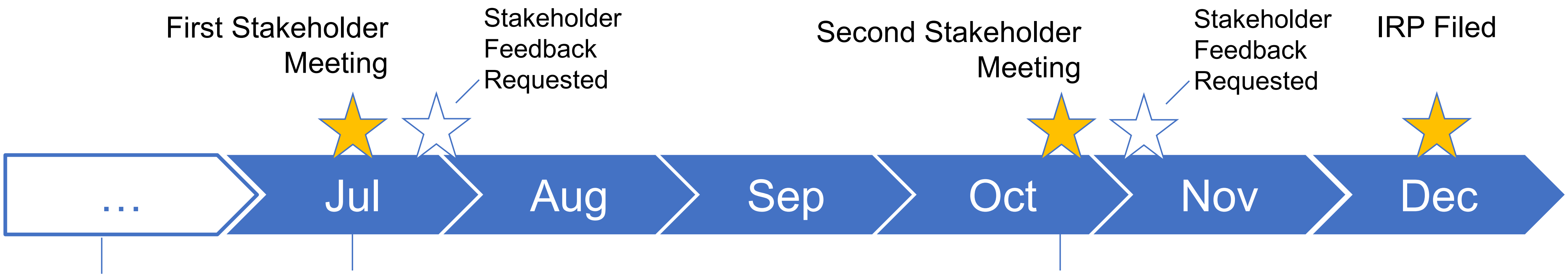
Feedback & Stakeholder Process

- Kentucky Power Plans to address 2019 IRP Recommendations and conduct two public stakeholder meetings as part of 2022 IRP Feedback Process
- The Company will consider prior comments and forthcoming stakeholder feedback on IRP inputs and initial outputs before selecting a final preferred plan



<u>Key Tasks</u>
- Review 2019 Recommendations
- Perform Market Research
- Draft IRP Inputs Developed
- Market Potential Study Initiated
- Draft Scorecard Development

<u>IRP Inputs Meeting:</u>
- IRP Process and Objectives
- PJM Market Scenarios
- Portfolio Development
- The IRP Scorecard

<u>IRP Initial Findings Meeting:</u>
- Update on Stakeholder Feedback & Inputs
- Market Scenario Results
- Review of Candidate Portfolios
- Draft Scorecard & Initial Indicators

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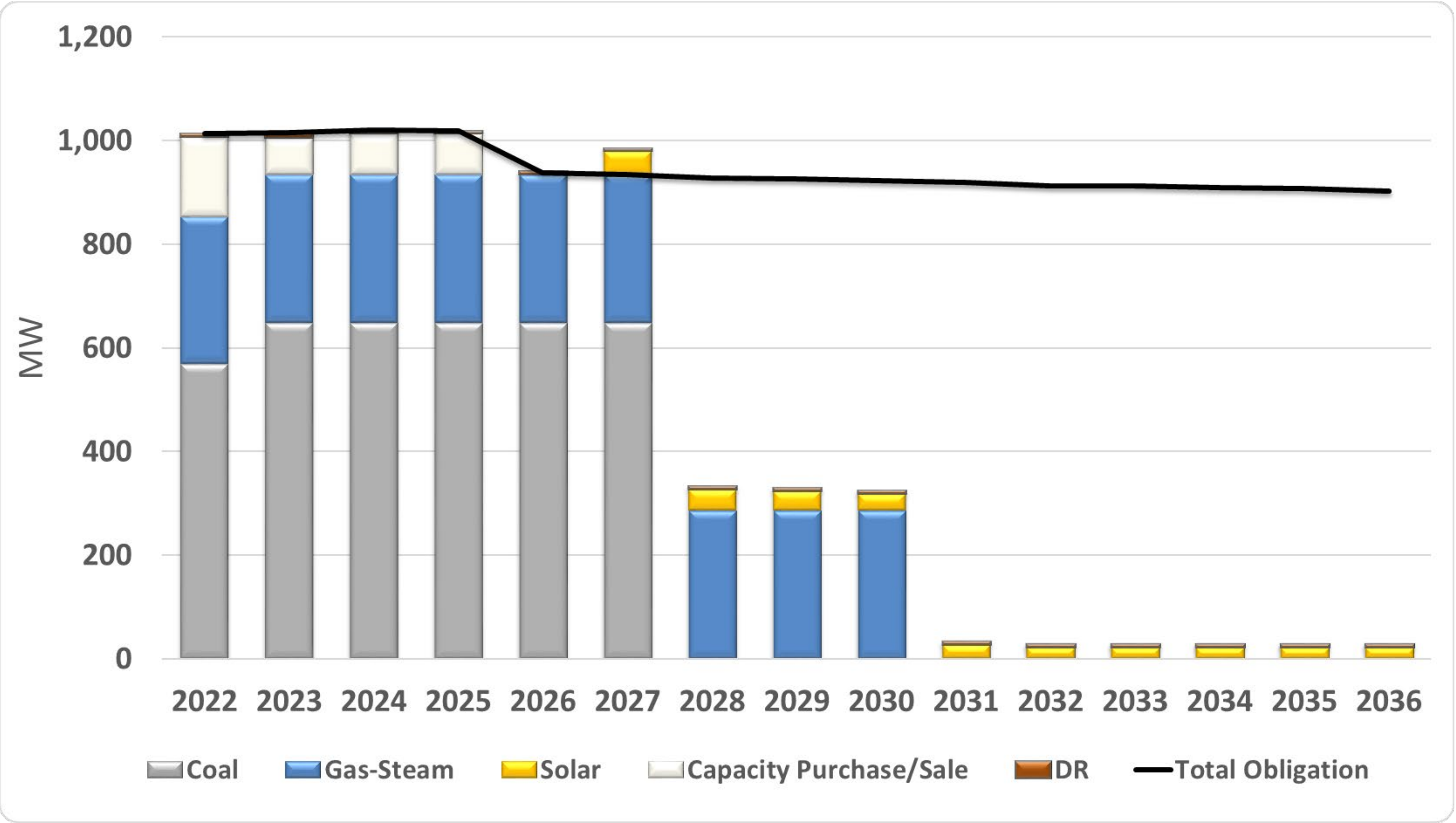
2022 IRP Starting Capacity Position



The loss of Mitchell after 2028 and Big Sandy after 2030 leave Kentucky power with a significant gap after the Rockport UPA expires in 2022

IRP Portfolios are developed and evaluated using the Market Scenarios

IRP Scenarios Determine Market Prices, Tech Costs, Load & ELCC Inputs

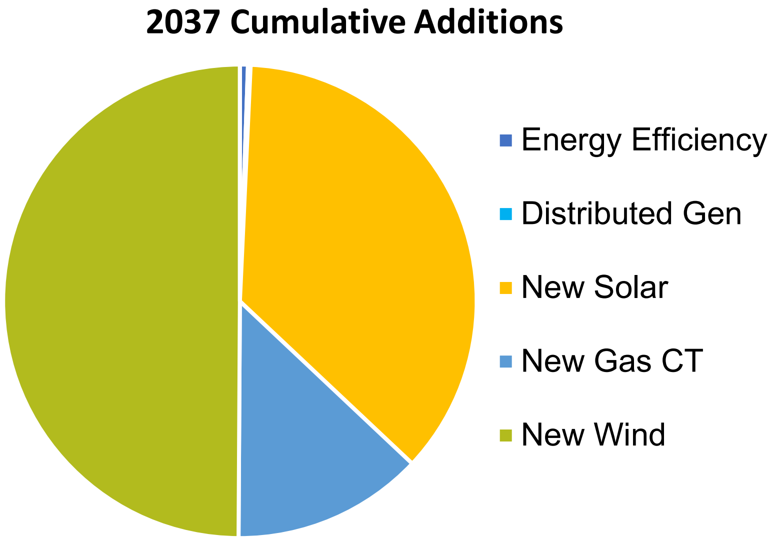
- Reference Scenario
- Reference Scenario with Higher Unit Costs
- Clean Energy Technology Advancement
- Enhanced Carbon Regulation
- No Carbon Regulation

CRA Develops Resource Alternatives to Test Under Market Scenario Conditions

Demand-Side Options:
- Energy Efficiency
- Distributed Generation
- VVO and DR

Supply-Side Options:
- Wind and Solar PV
- Gas-fired CTs and CCs
- 4hr-Battery Storage
- Carbon Capture Retrofits
- Hydrogen-fired CTs
- Advanced Nuclear & Storage

AURORA Selects the Least-Cost Combination of New Resources



Because optimizations may return a narrow set of potential resource plans, CRA also develops thematic replacement options (e.g., “no new gas”, “storage heavy”, etc.) to test tradeoffs between resource options

Candidate portfolios will be evaluated on an IRP Scorecard

- The Scorecard does not select the Preferred Plan by itself, rather it illustrates the trade-offs between alternative resource strategies across performance indicators and metrics defined under each objective.
- KY Power will select a preferred plan that limits cost and risk and meets other IRP objectives.

The IRP Scorecard is aligned to Objectives defined by the Company and its customers

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-yr Rate CAGR, Reference Case*	***Long Term:*** *15-yr CPW, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 15-yr CPW*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside Service Territory*	***CO2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2037	2022-2037	2027 | 2037	2037	2022-2037	2027 | 2037	2037	2022-2037	2027 | 2037
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM Levelized Rate	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction
Portfolio 1										
...										

Different KY Power portfolios are tested and results compared across all IRP objectives

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Stakeholder feedback is encouraged throughout the presentation

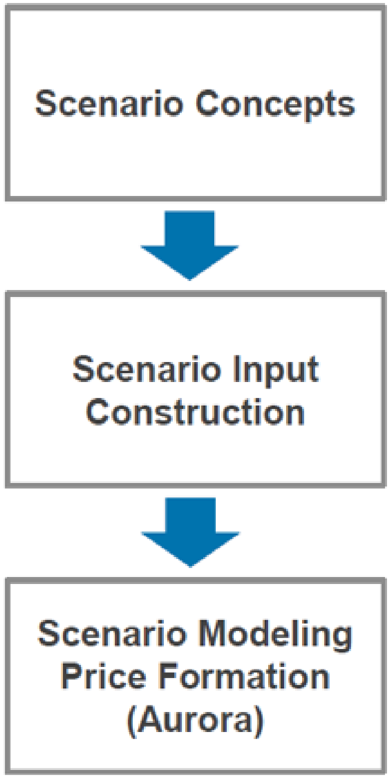
What Are Market Scenarios?

- Diverse, but possible, future states of the world
- Include multiple linked and correlated key variables
- Do <u>not</u> depend on future Kentucky Power decisions - reflect broad market outcomes under which portfolio decisions can be tested
- Scenario modeling encompasses the entire Eastern Interconnect with focus on capturing broad <u>market-level</u> outcomes in PJM

Scenario Modeling

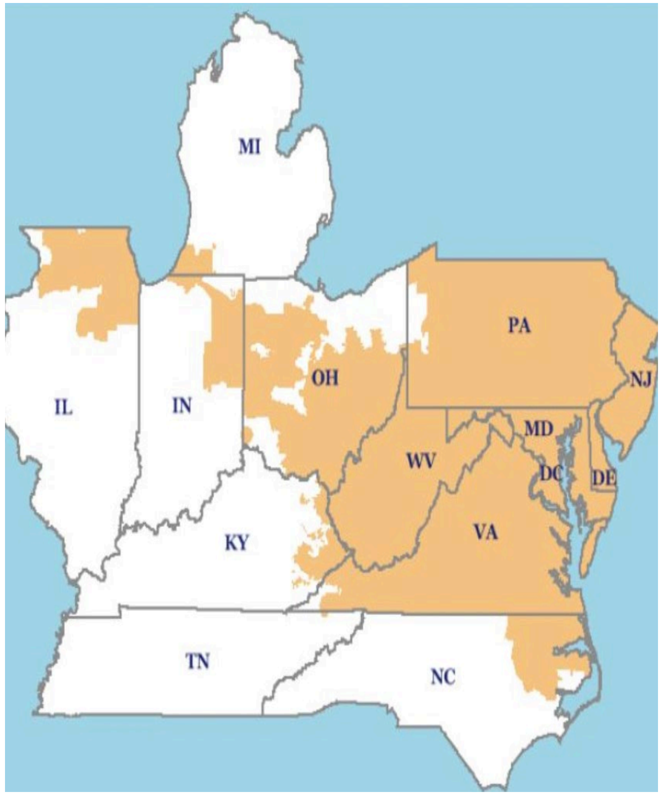
Example
Base Case, Market Stagnation, Carbon limit

Example inputs:
Load forecast, fuel price forecast, CO2 price forecast, Tech costs



Output:
Prices reflect integrated set of inputs

PJM Footprint



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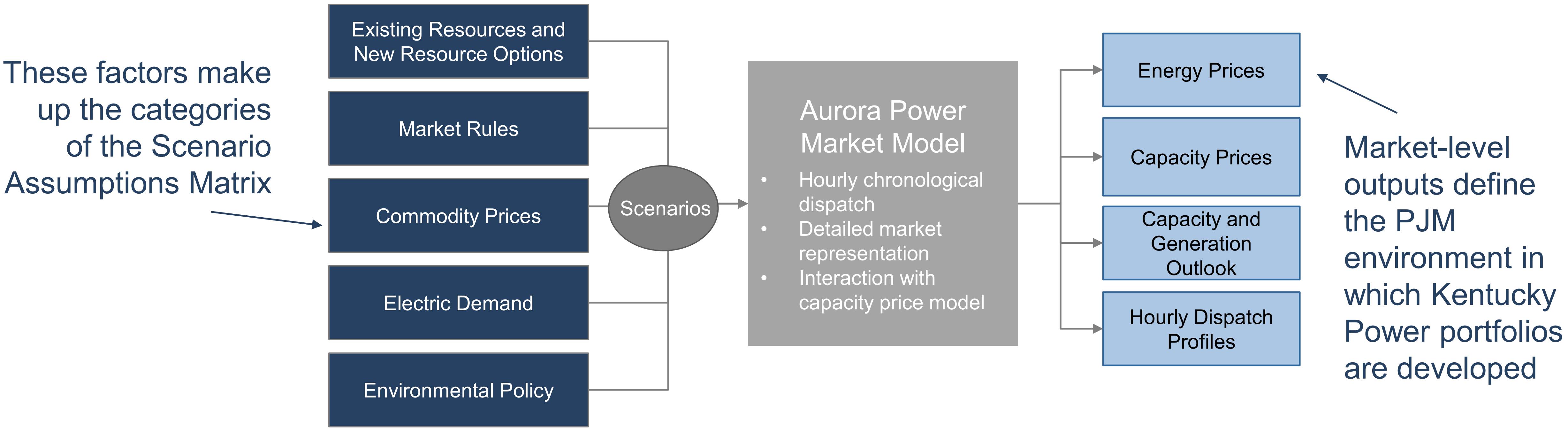
Market Scenario outputs are used to develop and test KY Power portfolios

CRA uses the AURORA Model to forecast electric market outcomes under different scenarios designed to simulate materially different plausible market futures that test the key risks to the company and its customers.



Considerations for 2022 IRP Market Scenarios

- Future fuel price uncertainty remains an important factor for evaluation
- Environmental policy evolution is a major uncertainty for resource planners, and this covers many dimensions
  - Future federal action, if it develops, could take many forms (e.g., CO2 Pricing, Emissions Caps, Clean Energy Standard, or extension of tax credit & subsidies)
  - State-level initiatives and corporate targets will impact power mix in the absence of federal action
- Load growth uncertainty is expanding beyond traditional economic factors, with a growing focus on electrification potential and DERs
  - Customer behavior may influence electrification and distributed energy resource penetration
- Technological change and the costs of new resource options will significantly impact utility decisions and the evolution of the broader power markets
  - Changes to the PJM reliability construct could affect the ELCC of intermittent and energy-limited resources

Proposed 2022 IRP PJM Market Scenarios

Reference Scenario

- The PJM market continues to evolve based on the current outlook for load growth, commodity prices, technology development, and regulatory pressure.

Reference Scenario with Higher Unit Costs [Sensitivity]

- The PJM market continues to evolve based on the current outlook for load growth, commodity prices, and regulatory pressure. New unit costs remain elevated as short-term shocks to the supply chain are not fully resolved over the forecast period.

Clean Energy Technology Advancement

- Extension of federal renewable tax credits (and expansion to storage) and continued technology improvements result in low technology costs for new wind, solar, and storage. Widespread adoption of EVs and electrification results in high load growth.

Enhanced Carbon Regulation

- Carbon emissions are regulated through a federal carbon cap and trade program that results in a significant CO_2 price and a long-term power sector net zero trajectory. Higher natural gas prices due to production restrictions.

No Carbon Regulation

- Natural gas pricing revert to lows observed in recent years, this combines with no federal carbon regulation to provide more favorable market conditions for gas and coal resources vs. renewables relative to the Reference Case

All 2022 IRP Market Scenarios incorporate impacts of regional policies (RGGI, RPS) in PJM

The PJM Market Scenarios Combine Multiple Fundamental Elements

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Higher
3	Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Faster Decline w/ 10-yr PTC/ITC ext.
4	Enhanced Carbon Regulation (ECR)	Low	High	High	Faster Decline w/ higher congestion
5	No Carbon Regulation (NCR)	Base	Low	No Price	Base

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Load

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Higher
3	Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Faster Decline w/ 10-yr PTC/ITC ext.
4	Enhanced Carbon Regulation (ECR)	Low	High	High	Faster Decline w/ higher congestion
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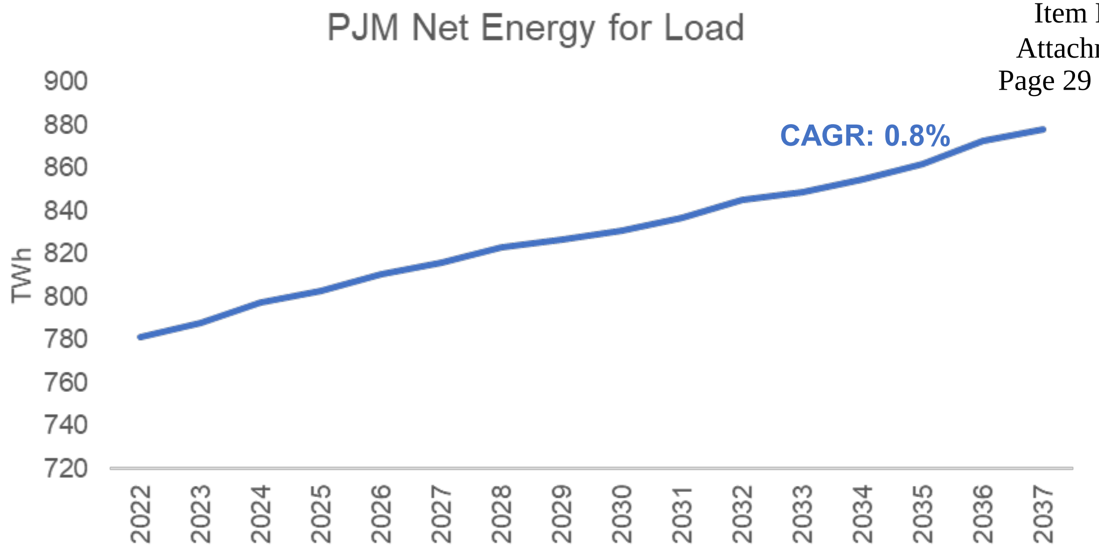
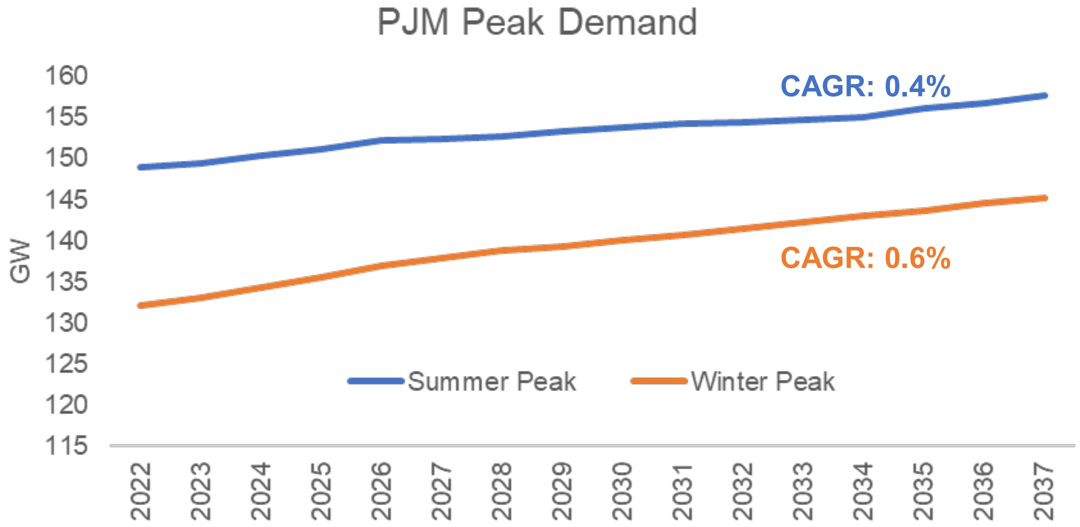
PJM Load Growth Expectations

- For **PJM market modeling**, CRA will rely on the latest forecasts provide by the RTO as the "Base" view for scenario modeling
  - Winter peak demand is growing faster than summer peak demand across the PJM footprint

- As a reminder, PJM-wide growth is used only for scenario modeling.
  - Kentucky Power's load will be studied in the portfolio model to develop candidate resource plans





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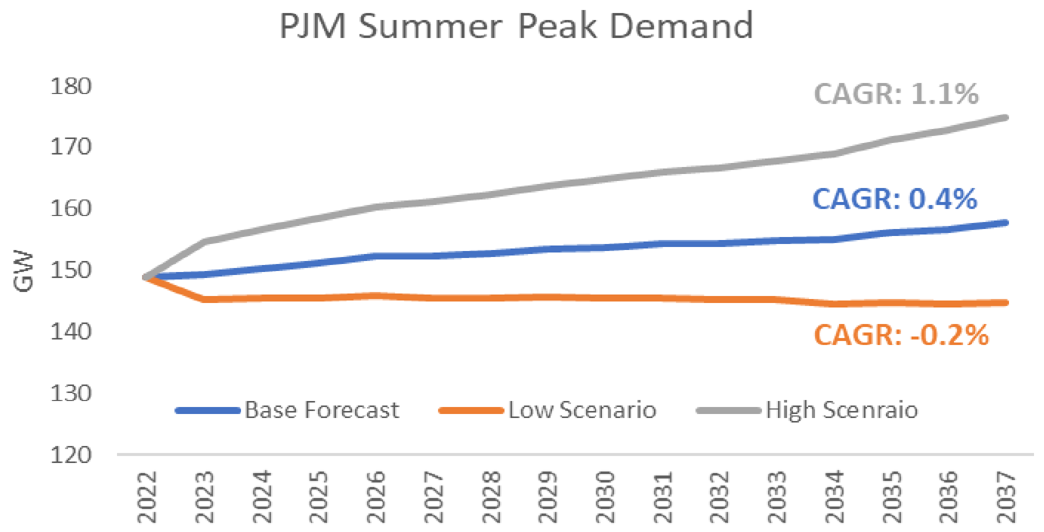
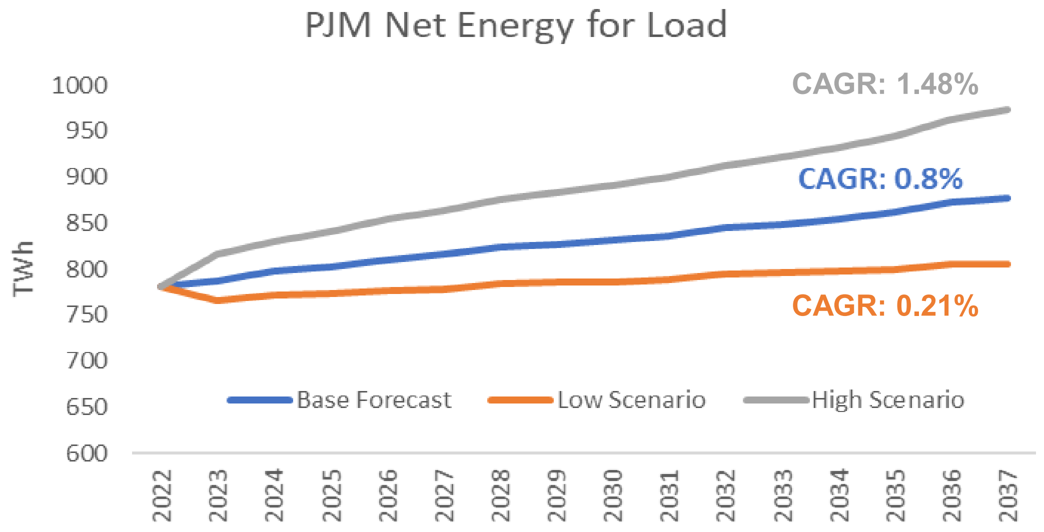
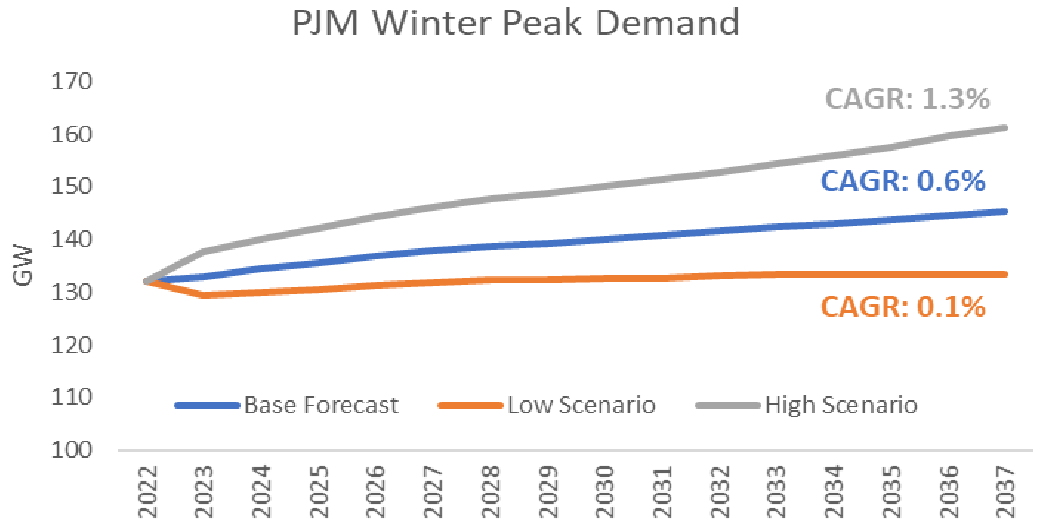
Load Forecast

- KY Power will also test "High" and "Low" PJM outlooks to evaluate the risk of higher or lower loads on the selection of new resources







Reserve Margin Requirement

- Currently, PJM's Installed Reserve Margin (IRM) target is between 14.7-14.9% above summer peak load for the upcoming planning years
  - CRA will model this requirement as a firm constraint on the PJM market model for the LTCE runs
- KY Power will evaluate native winter peak demand in the 2022 IRP portfolio modeling phase
  - KY Power will develop portfolios that secure the resources needed to meet winter peak demand for its customers in addition to annual PJM summer requirements

2021 PJM RRS Study Results

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2021	2022 / 2023	14.93%	**14.9%**	5.08%	**1.0906**
2021	2023 / 2024	14.76%	**14.8%**	5.04%	**1.0901**
2021	2024 / 2025	14.68%	**14.7%**	5.02%	**1.0894**
2021	2025 / 2026	14.66%	**14.7%**	5.02%	**1.0894**

PJM's 2024/2025 BRA Reserve Requirement Parameters

Delivery Year	Required IRM	Average EFORd	Recommended FPR
2024/2025	14.68%	5.02%	1.0894

Natural Gas

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Higher
3	Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Faster Decline w/ 10-yr PTC/ITC ext.
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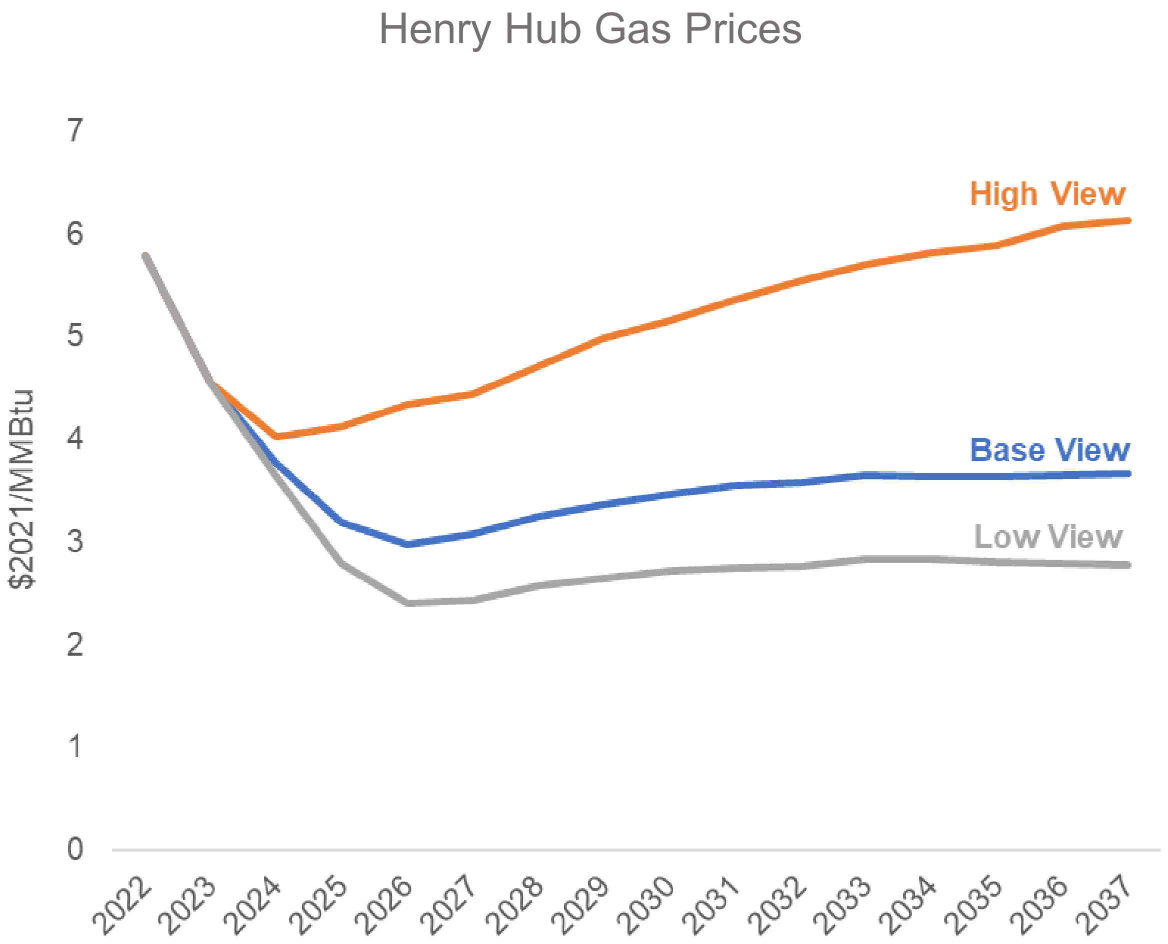
Natural Gas Price Ranges



- KY Power sets the range of long-term gas forecasts using EIA's 2022 Annual Energy Outlook forecasts
- Over the first 4 years, recent market data informs expected prices, blend into the AEO views

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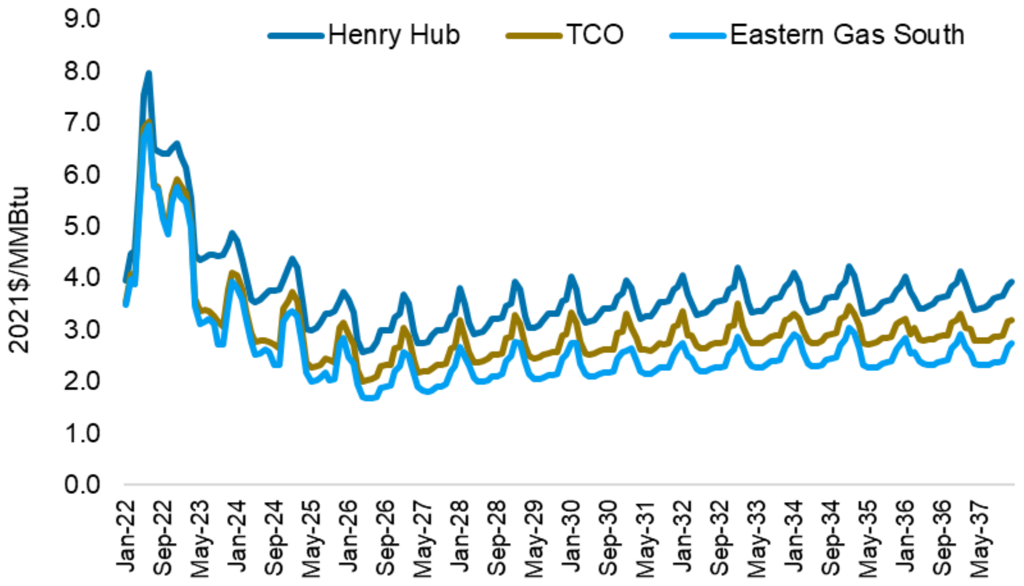
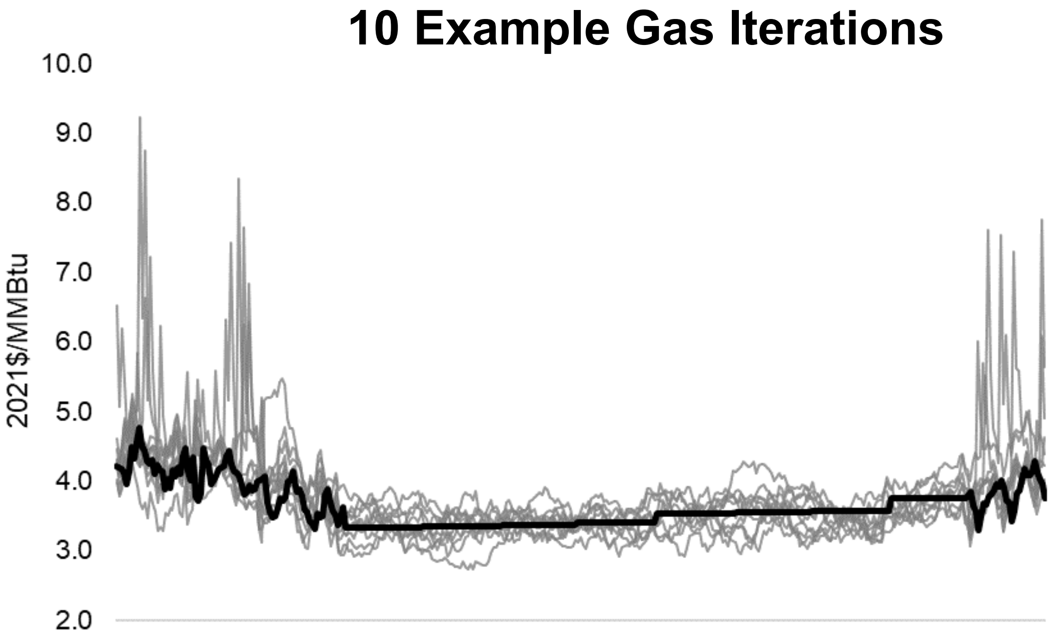
Natural Gas Price Volatility





- In the Market Scenarios, seasonal prices and regional basis are forecast for key market hubs
- Natural gas prices include daily volatility

- Stochastic analysis is used to evaluate portfolio sensitivity to random price shocks and market volatility

Carbon Price

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Higher
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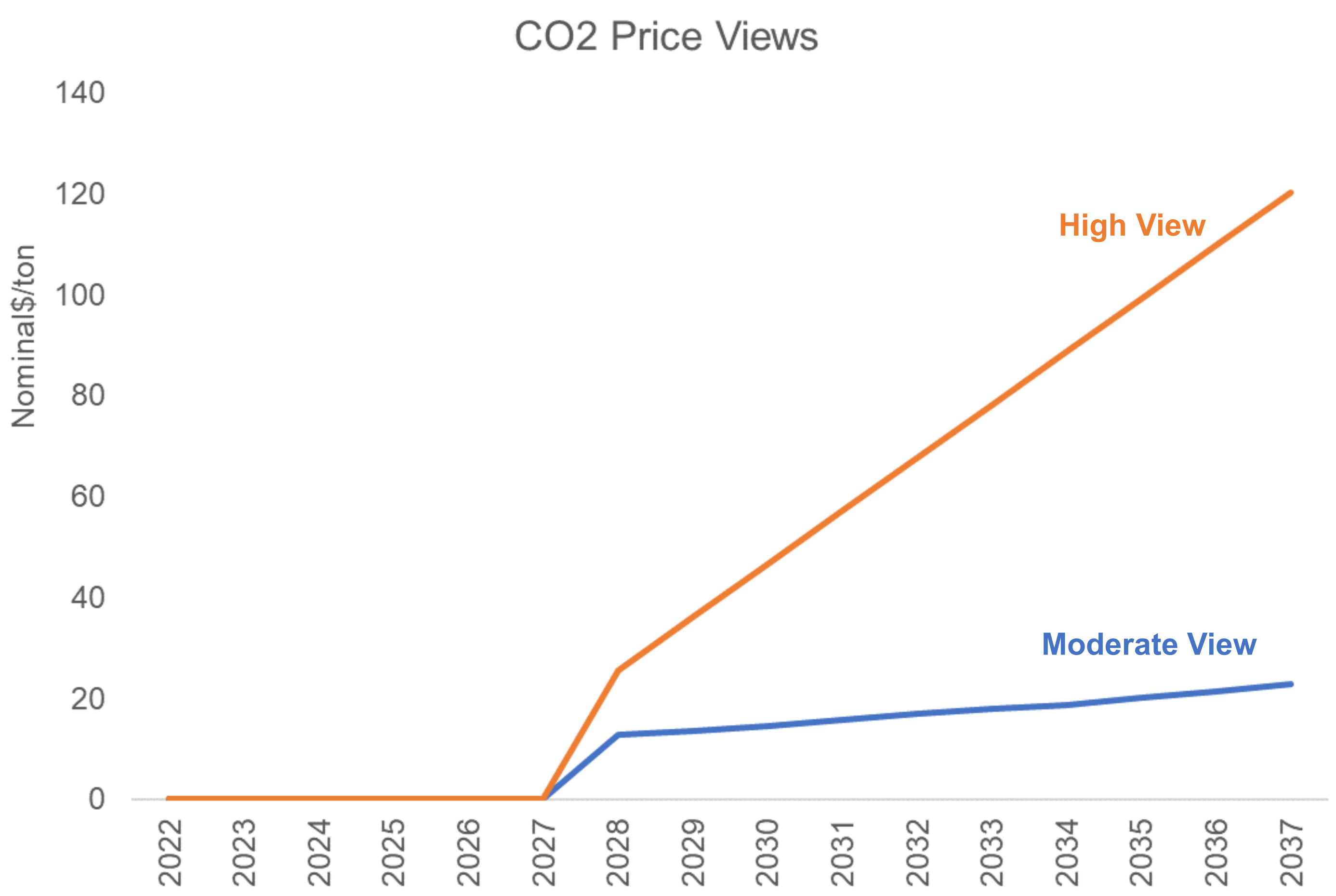
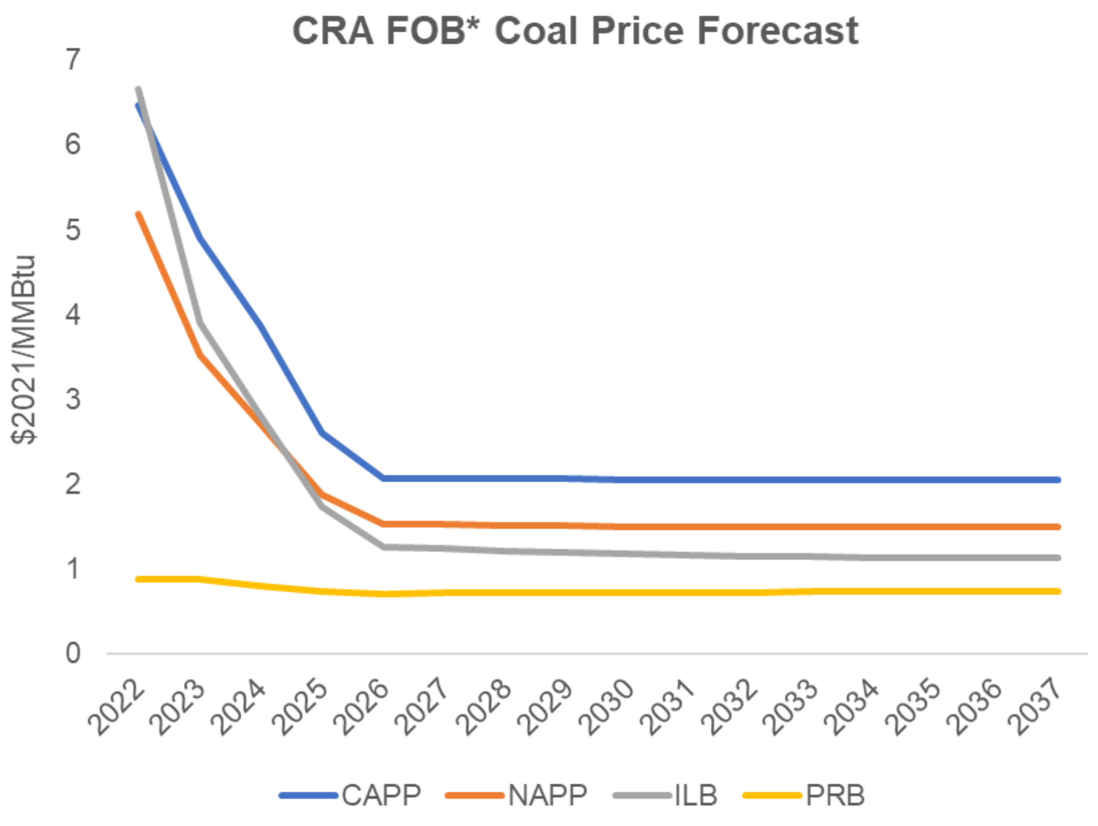
Carbon Price Ranges



- CO2 prices are assumed to be first implemented in 2028
- The High view assumes that policymakers take more aggressive action to reduce CO2 emissions over the short term, and trends toward towards the price needed to achieve net-zero reductions in 2050
- The Moderate view reflects the long-term trajectory needed to achieve modest (e.g., 70%) electric-sector emissions reductions by 2050

Coal Prices



*The Free On Board price represents the value of coal at the coal mine and excludes transport and insurance costs

- U.S. coal prices exhibit flat-to-declining trends over the long-term due to continued coal retirement expectations in the US
- Over the long term, U.S. domestic demand for coals is expected to decline significantly, in proportion to the projected declines in U.S. demand for coal-fired generation throughout the forecast period

Technology Costs

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Higher
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4	Enhanced Carbon Regulation (ECR)	Low	High	High	Faster Decline w/ higher congestion
5	No Carbon Regulation (NCR)	Base	Low	No Price	Base

New supply-side resources

CRA will evaluate a broad range of resource types as part of the 2022 IRP that includes thermal, renewable, and emerging technologies that may be needed to support future electric-sector decarbonization.

Intermediate & Peaking Options

- H-Class 430 MW single-shaft natural gas combined cycle (NGCC)
- H-Class 1,100 MW multi-shaft NGCC
- F-Class 240 MW natural gas combustion turbine (NGCT)
- 650 MW ultra-supercritical coal (USC) unit with 90% carbon capture
- 430 MW H-class single shaft NGCC with 90% carbon capture
- 100 MW aeroderivative unit
- 20 MW reciprocating engine
- 4-hour duration lithium-ion battery

Renewable Options

- Utility-scale onshore Wind
- Utility-scale solar photovoltaic
- Utility-scale paired solar + storage

Advanced Generation & Storage

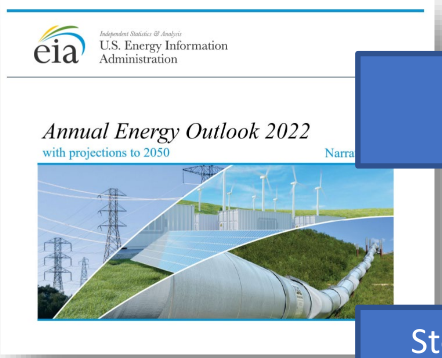
- Small modular nuclear reactors
- 90% carbon capture retrofits to existing coal or NGCC units
- Hydrogen electrolyzer + hydrogen gas combustion turbine
- Hydrogen gas combustion turbine
- 20-hour duration pumped thermal energy storage
- 20-hour vanadium flow battery storage
- 20-hour compressed air energy storage

Approach to Developing New Unit Assumptions

Inputs for these resources have traditionally been developed based on authoritative third-party sources.

Intermediate & Peaking Options

Renewable Options

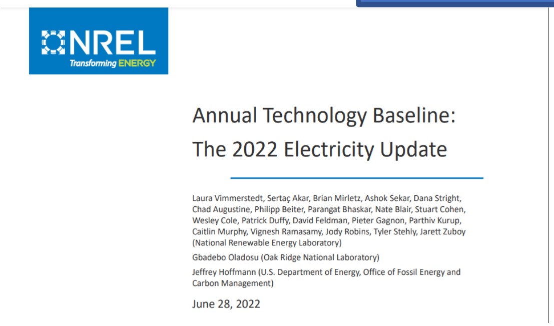

U.S. Energy Information Administration

Annual Energy Outlook 2022

with projections to 2050

Step 1: Sourcing baseline technology costs and performance assumptions from EIA Annual Energy Outlook*

Step 2: Applying changes to technology cost and performance over time based on the Moderate Case projection by the National Renewable Energy Laboratory's Annual Technology Baseline*


NREL Transforming ENERGY

Annual Technology Baseline:
The 2022 Electricity Update

Laura Vimmerstedt, Sertaç Akar, Brian Mirletz, Ashok Sekar, Dana Stright, Chad Augustine, Philipp Beiter, Parangat Bhaskar, Nate Blair, Stuart Cohen, Wesley Cole, Patrick Duffy, David Feldman, Pieter Gagnon, Parthiv Kurup, Caitlin Murphy, Vignesh Ramasamy, Jody Robins, Tyler Stehly, Jarett Zuboy (National Renewable Energy Laboratory)

Gbadebo Oladosu (Oak Ridge National Laboratory)

Jeffrey Hoffmann (U.S. Department of Energy, Office of Fossil Energy and Carbon Management)

June 28, 2022

Step 3: Applying investment tax credit for wind project entering service before the end of 2025, and 30% production tax credit for solar project entering service before the end of 2023, 26% before the end of 2025 and 10% thereafter

Advanced Generation & Storage

Step 1: Collate projections of technology costs and performance from various third-party sources

Step 2: Analyze projections, identify outliers and form central estimates of technology costs and performance over time

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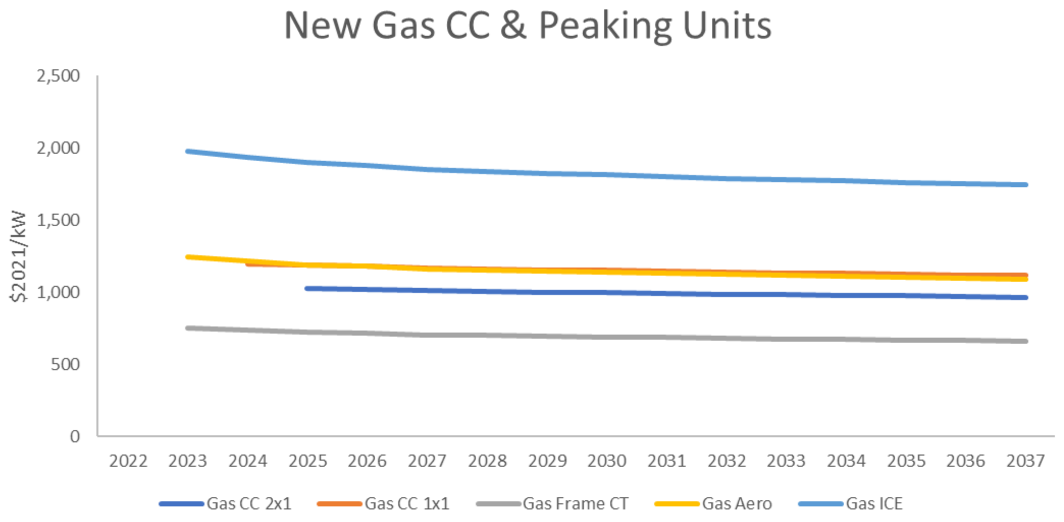
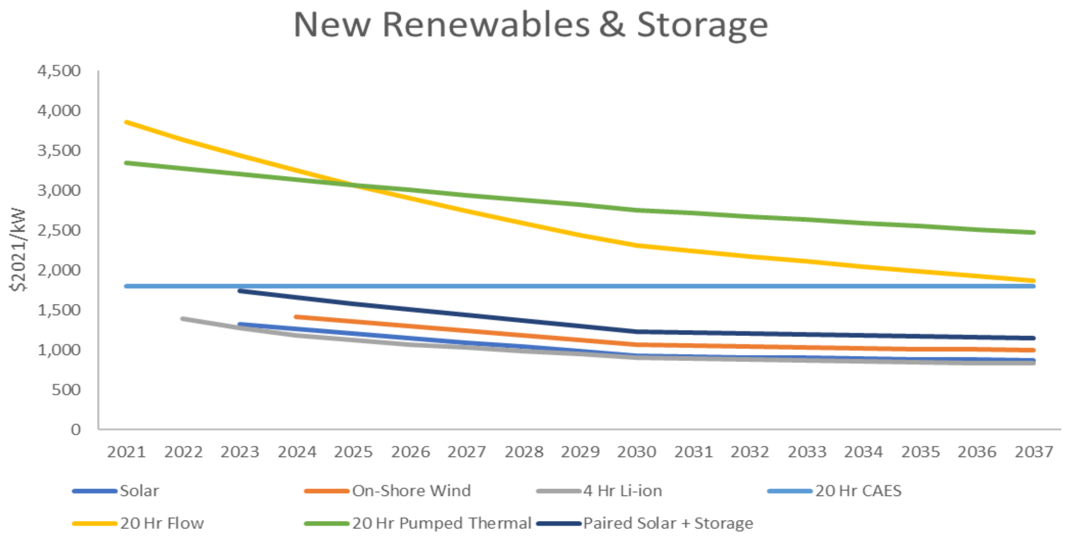
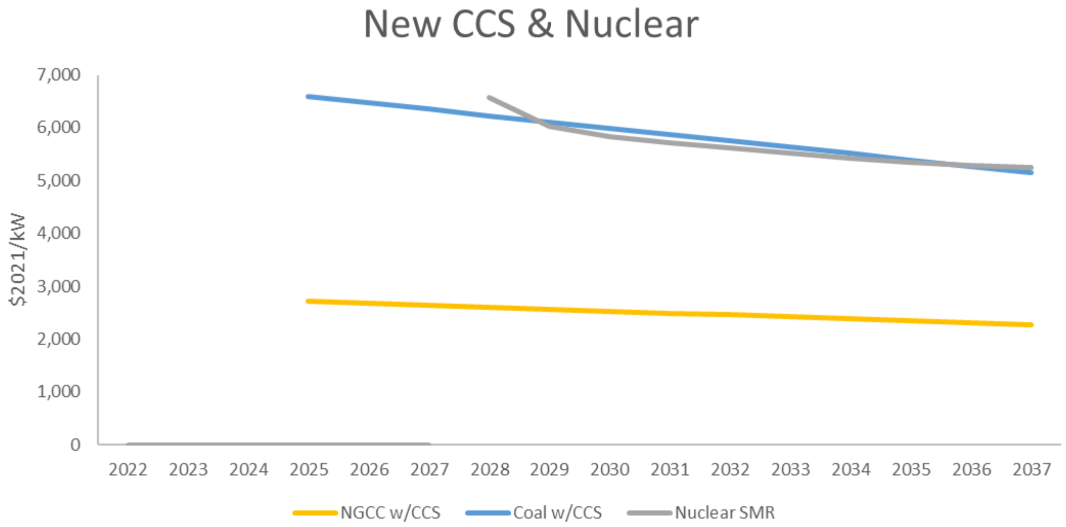
Utility-Scale Capital Costs

- KY Power relies on publicly available sources to estimate the cost of new utility-scale resources







DRAFT Indicative Considerations for Discussion

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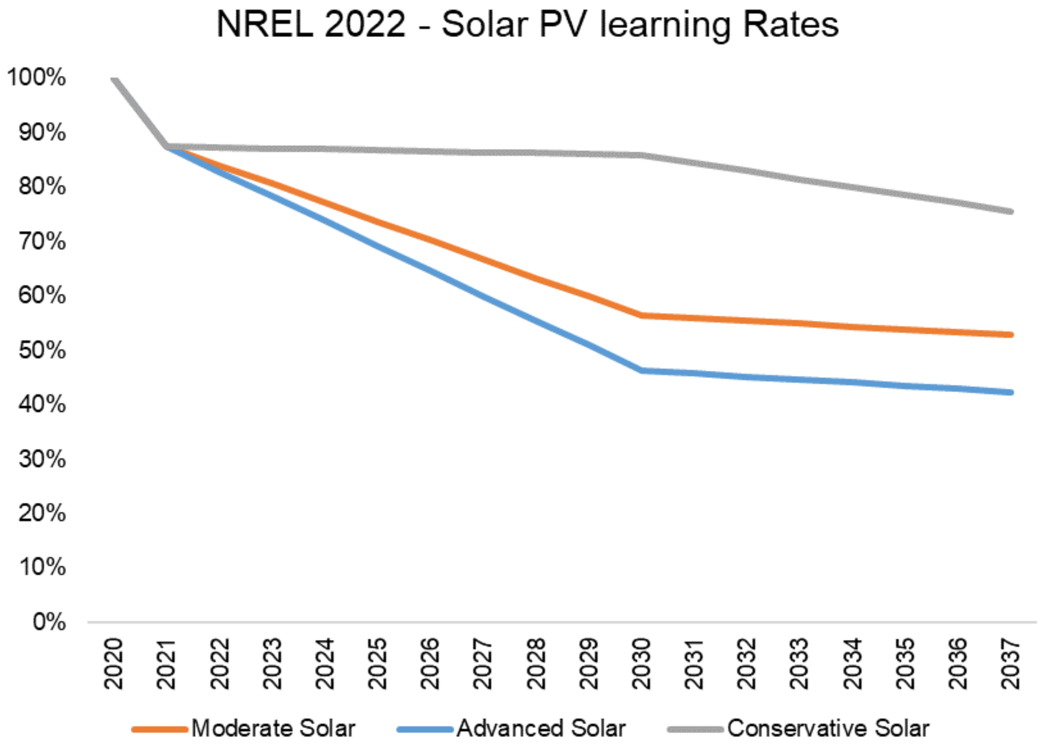
New Unit Cost Assumptions

- Under all cases, KY Power will include the short-term impacts of supply chain disruptions new unit costs.
- KY Power believes that the current market disruptions driving higher unit costs are a short-term phenomenon and expects market participants to resolve supply-chain issues over the medium-to-long term.
- Under the "Base" and "Faster Decline" technology cost views, supply chain issues are resolved and the cost of new units declines to align with NREL "moderate" and "advanced" forecasts over the medium-term.
- Under the "Higher" technology cost sensitivity, KY Power will test the risk that supply chain issues persist and are not fully resolved.
  - The recovery to "normal" pricing will take longer in this sensitivity, and future learning will follow NREL's "conservative" forecast of technology cost improvement.



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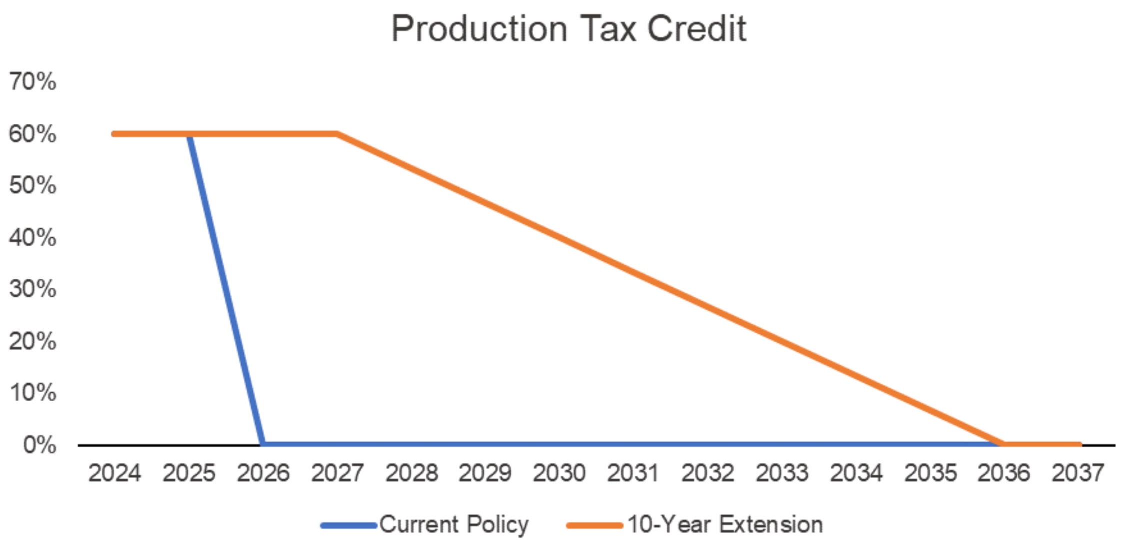
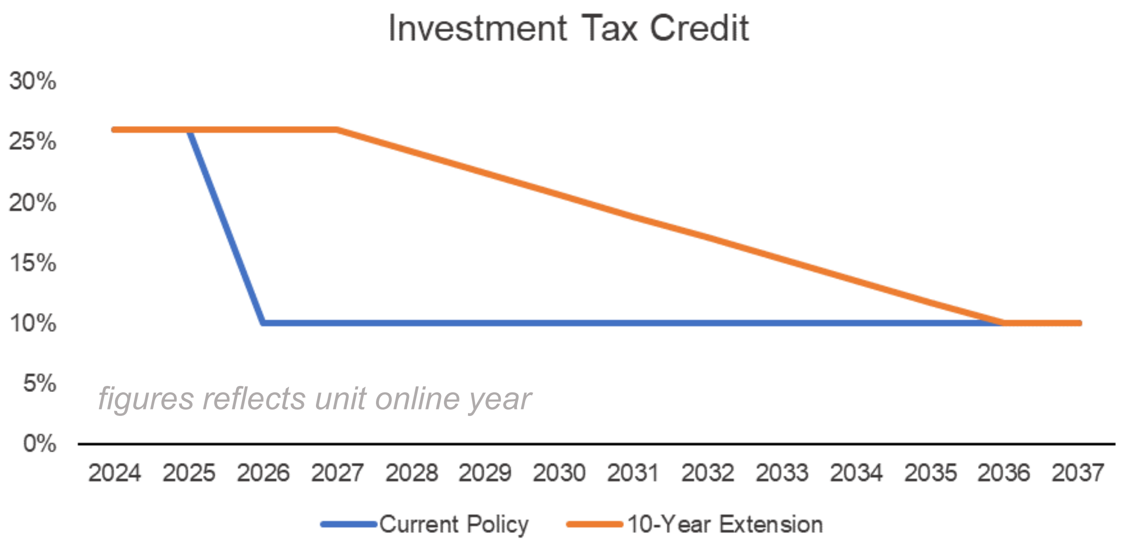
Outlooks for PTC / ITC extension

- Under most scenarios, CRA assumes that the value of Federal tax credits declines or expires based on the current law.
- Under the CETA scenario, it is assumed that these tax credits are extended for 10 years and decline gradually, consistent with the theme of providing support for clean technologies as a method to achieve CO2 reductions.





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Current ELCC Ratings in PJM

- PJM recently updated its approach to estimating ELCC values for certain resource classes:
  - Variable Resources (e.g., renewables)
  - Limited-Duration Resources (e.g., storage)
  - Combination Resources (e.g., renewable or storage combined with one or more other types).

- Unlimited Resources (e.g., thermal units) are awarded UCAP based on nameplate MW and forced outage rates.

2024/2025 BRA ELCC Class Ratings

ELCC Class	ELCC Class Rating for 2024/2025 BRA
Onshore Wind	16%
Offshore Wind	37%
Solar Fixed Panel	36%
Solar Tracking Panel	54%
4-hr Storage	82%
6-hr Storage	97%
8-hr Storage	100%
10-hr Storage	100%
Solar Hybrid Open Loop - Storage Component	82%
Solar Hybrid Closed Loop - Storage Component	82%
Hydro Intermittent	46%
Landfill Gas Intermittent	60%
Hydro with Non-Pumped Storage*	96%

* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

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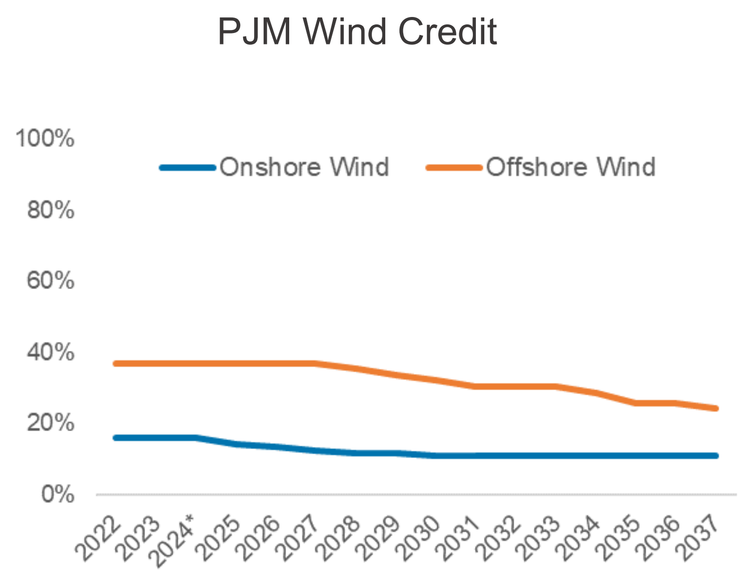
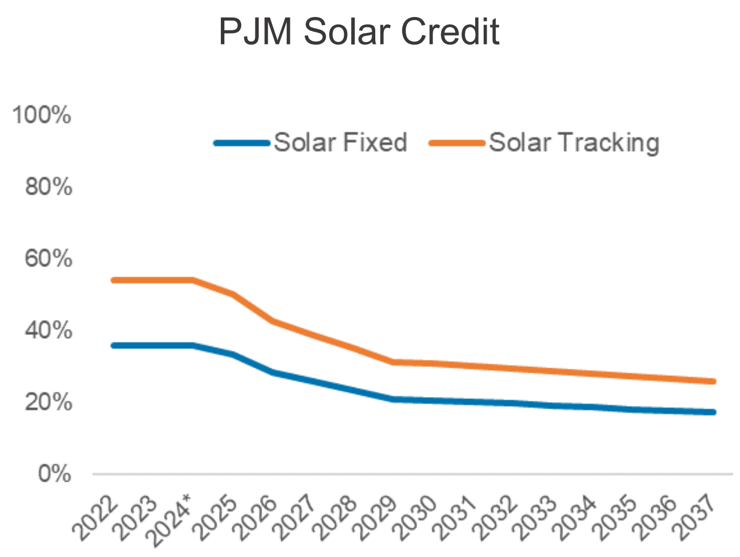
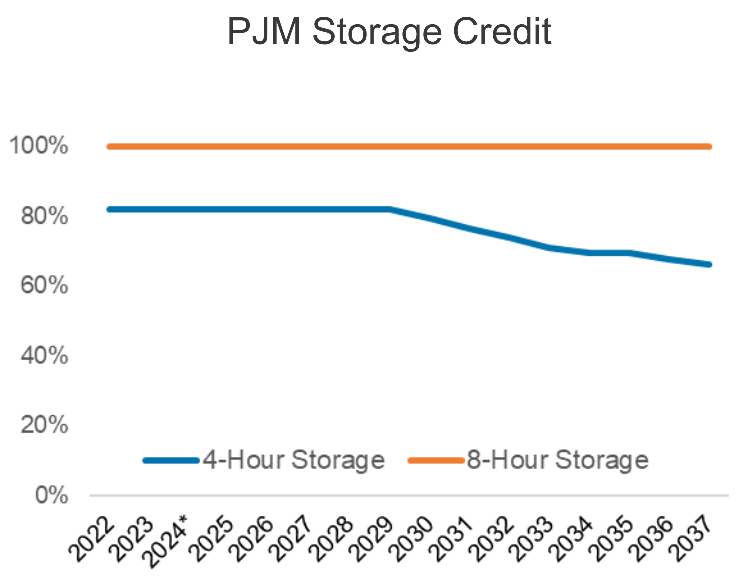
PJM ELCC class ratings will change over time

Overall, the capacity credit are expected to decline over time as more ELCC resources are added to the system





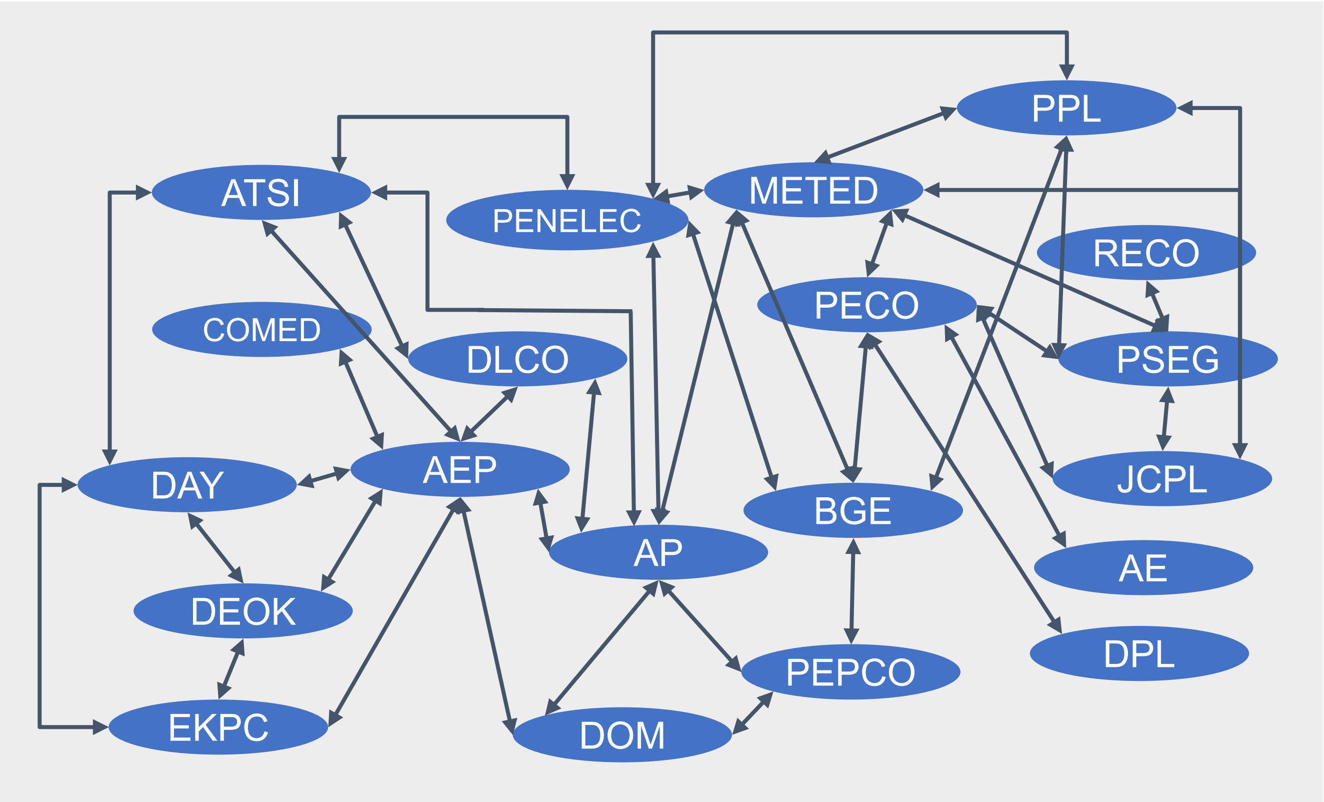


- In 2024, the ELCC values reflect PJM’s 2024/2025 Base Residual Auction ELCC class ratings
- Beyond 2024, assumed ELCC values reflect preliminary capacity expansion in PJM region.

Transmission

- AURORA is modeled in a zonal configuration of market demand regions with interconnecting transmission
  - PJM market regions can trade with one another to meet requirements, with losses
  - New resources may have interconnection and congestions costs defined in each market region
  - Under some scenarios congestion costs may be higher, or it may cost more to connect new resources to the system

PJM Network Representation*



*For illustration purposes only, CRA models all Eastern Interconnect links, including PJM with non-PJM connections, zonal representation and operating rules.

Questions?

Agenda

- Welcome and Introductions
- Overview of the 2022 IRP Process
- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
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- Discussion & Closing Remarks

Stakeholder feedback is encouraged throughout the presentation

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IRP Portfolios are developed and evaluated using the Market Scenarios

IRP Scenarios Determine Market Prices, Tech Costs, Load & ELCC Inputs


Reference Scenario


Reference Scenario with Higher Unit Costs


Clean Energy Technology Advancement


Enhanced Carbon Regulation

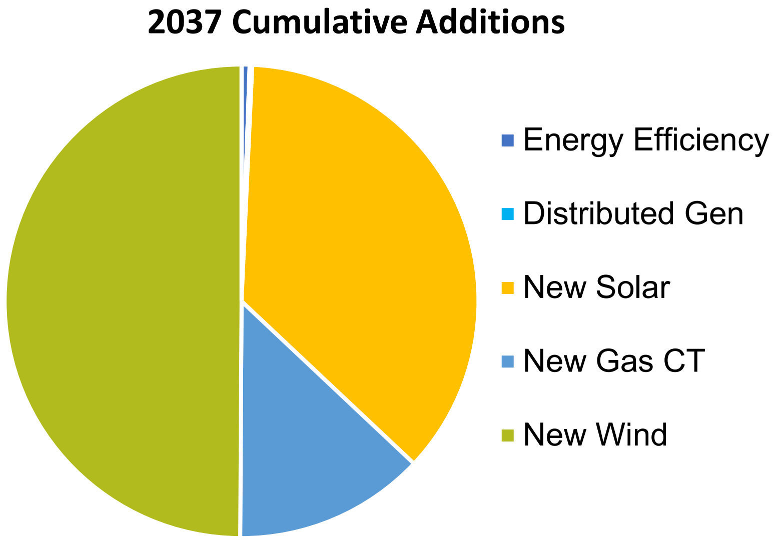

No Carbon Regulation

CRA Develops Resource Alternatives to Test Under Market Scenario Conditions

Demand-Side Options:
- Energy Efficiency
- Distributed Generation
- VVO and DR

Supply-Side Options:
- Wind and Solar PV
- Gas-fired CTs and CCs
- 4hr-Battery Storage
- Carbon Capture Retrofits
- Hydrogen-fired CTs
- Advanced Nuclear & Storage

AURORA Selects the Least-Cost Combination of New Resources



Because optimizations may return a narrow set of potential resource plans, CRA also develops thematic replacement options (e.g., "no new gas", "storage heavy", etc.) to test tradeoffs between resource options

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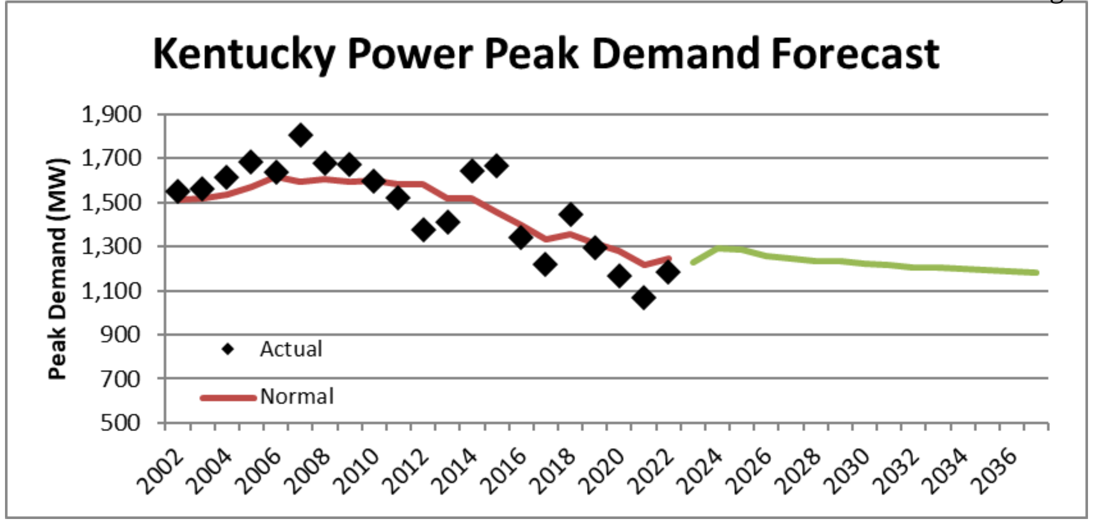
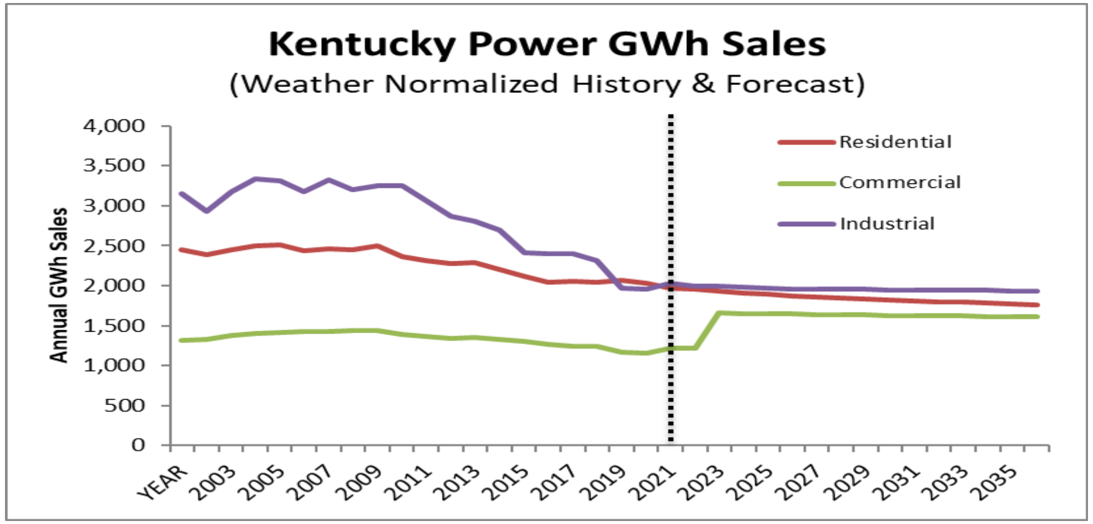
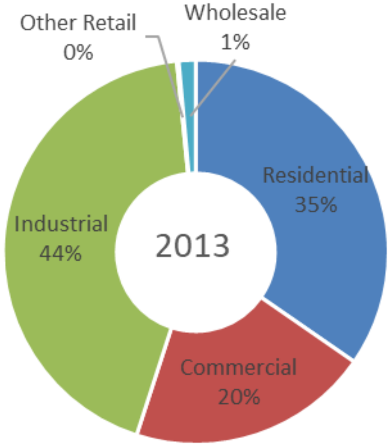
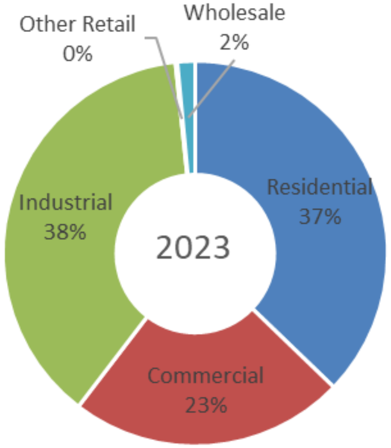
Kentucky Power Load Forecast

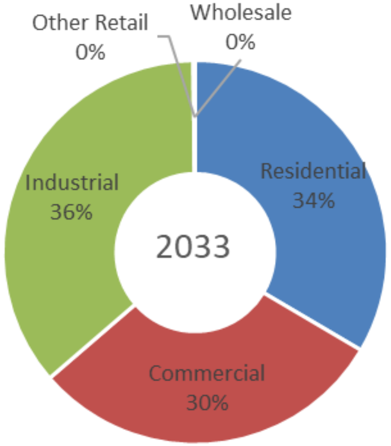
- KY Power peak demand forecast shows slight decline over the next decade (CAGR -0.2% from 2023-2033).
- Customer counts are expected to decline by 0.8% per year over the next decade.
- The mix of sales for KY Power load are also shifting, becoming more balanced between Residential, Commercial, and Industrial.











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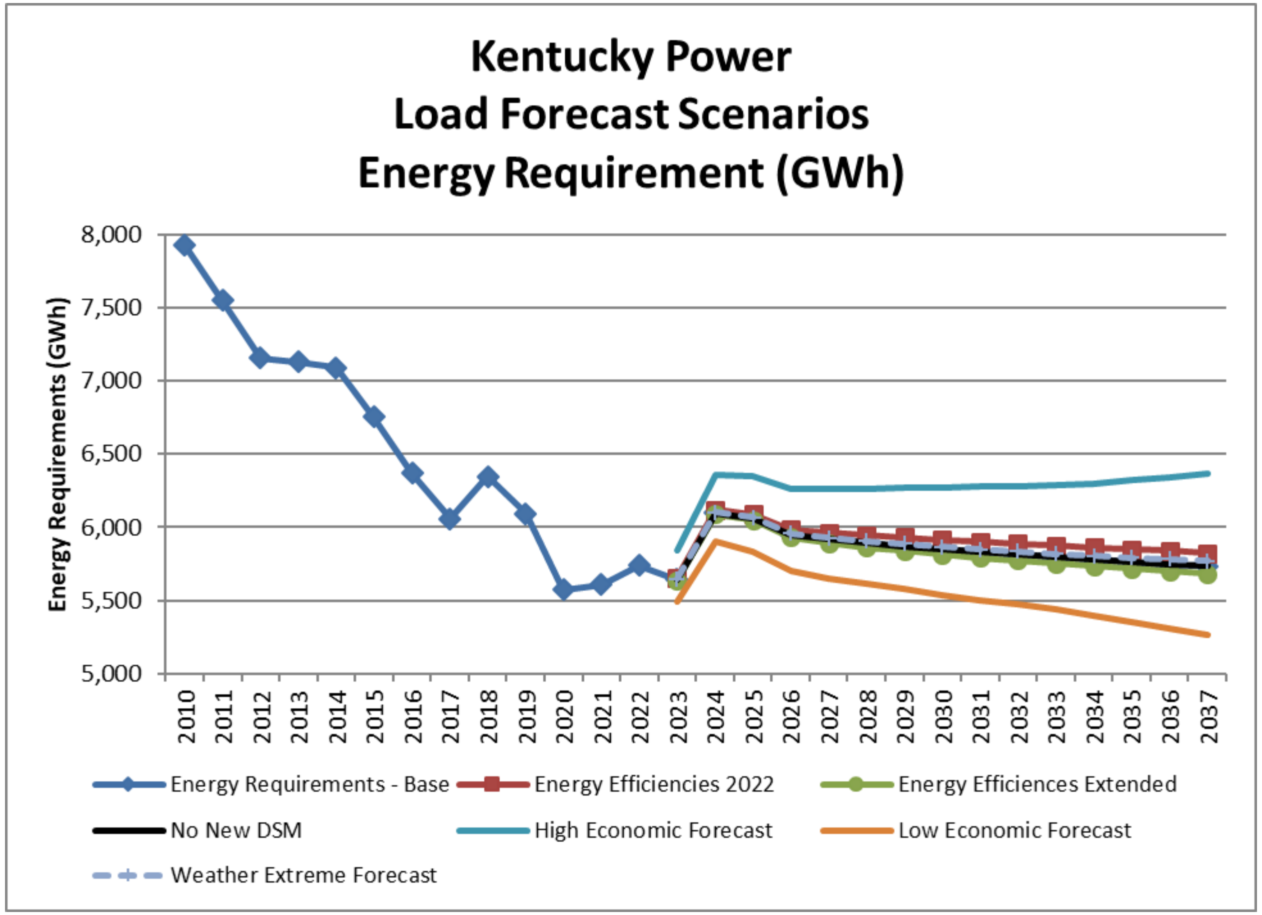
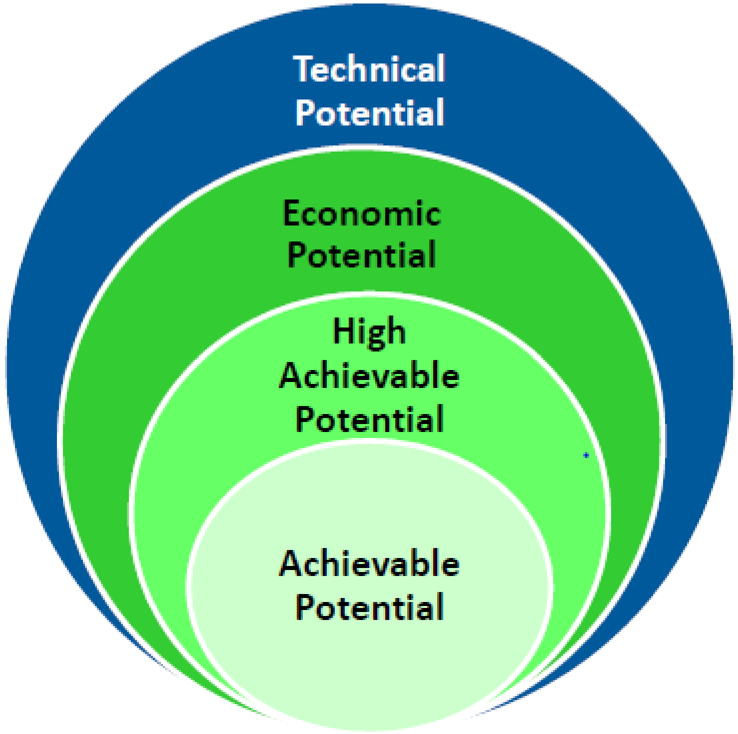
Kentucky Power Load Scenarios

- Multiple load scenarios were developed for KY Power.
- The High and Low Economic scenarios are provided for the IRP portfolio modeling to assess the performance of the various portfolios under the various load conditions.
- In addition to these, KY Power also developed various DER scenarios (e.g. Electric Vehicles and Distributed Generation resources), which were well within the High and Low Economic scenarios.



Kentucky Power will evaluate EE options as alternatives to new generation supply. The Company is initiating a Market Potential Study within the service territory, and preliminary results of this study will inform the 2022 IRP inputs.



Technical Potential: Every customer adopts the most efficient available measures, regardless of cost

Economic Potential: Every customer adopts the most efficient available measures that pass a basic economic screen

High Achievable Potential: Economic Potential discounted for market barriers such as customer preferences and supply chain maturity, indicative of exemplary EE programs

Achievable Potential: High Achievable discounted for programmatic barriers such as program budgets and execution proficiency; indicative of typical EE programs

Evaluation of the Preferred Plan

The resulting set of five candidate portfolios will be stress-tested to evaluate performance under adverse or unexpected conditions and the results populated in a Balanced Scorecard. This process has two steps:

Scenario Analysis
Tests Performance Under Integrated Set of Assumptions

- Each candidate portfolio is dispatched in every IRP Market Scenario to evaluate the level of customer exposure to higher costs under unexpected conditions
- This approach answers "what if…" questions and tests outcomes where major events change fundamental outlooks for key drivers after investments are made, altering portfolio performance

Stochastic Analysis
Tests Performance Under a Distribution of Inputs

- The stochastic analysis incorporates hourly volatility into energy prices, natural gas prices, and hourly renewable generation to test the impacts of extreme weather and high-cost market events
- Stochastics evaluate volatility and "tail risk" impacts
  - Market price volatility and resource output uncertainty are more complex than what can be assessed under "expected" or "weather normal" conditions
  - Commodity price exposure risk is broader than any single scenario range (i.e., February 2021 winter storm)

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Candidate portfolios will be evaluated on an IRP Scorecard

- The Scorecard does not select the Preferred Plan by itself, rather it illustrates the trade-offs between alternative resource strategies across performance indicators and metrics defined under each objective.
- KY Power will select a preferred plan that limits cost and risk and meets other IRP objectives.

The IRP Scorecard is aligned to Objectives defined by the Company and its customers

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-yr Rate CAGR, Reference Case*	***Long Term:*** *15-yr CPW, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 15-yr CPW*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside Service Territory*	***CO2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2037	2022-2037	2027 | 2037	2037	2022-2037	2027 | 2037	2037	2022-2037	2027 | 2037
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM Levelized Rate	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction

Performance Indicators on the Scorecard are measurable categories of performance that reflect the IRP Objectives

Metrics on the Scorecard are developed from the IRP modeling results and used to quantify performance and populate the IRP Scorecard

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Objective: Customer Affordability

The Customer Affordability indicators compare the cost to customers under the Reference Case Market Scenario over the short- and long-term. These metrics illustrate differences in performance under the expected case.

Performance Indicator	Metric	Description
Short-term	5-year Rate CAGR under the Reference Scenario (2022-2027)	• KY Power measures and considers the expected Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2022-2027 as the metrics for the short-term performance indicator. • **A lower number is better**, indicating slower growth in customer rates.
Long-term	15-yr CPW under the Reference Scenario (2022-2037)	• KY Power measures and considers the growth in Cumulative Present Worth ("CPW") over 15 years as the long-term metric. • CPW represents total long-term cost paid by KY Power related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital. • KY Power also evaluates the levelized rate for this indicator, which is the fixed charge needed on a per MWh basis to recover the15-yr CPW. • **A lower number is better**, indicating lower costs to supply customers with power.

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Objective: Rate Stability

The Rate Stability indicators compare the risk that cost to customers will be higher than expected, either due to a change in fundamental market conditions or due to short-duration high-impact events.

Performance Indicator	Metric	Description
Scenario Range	High Minus Low Scenario Range 15-yr CPW (2022-2037)	• KY Power measures and considers the range of 15-yr CPW reported by each portfolio across all PJM market Scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an CPW and levelized rate basis. • **A lower number is better**, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions.
Cost Risk	CPW Increase in Reference Scenario – 2027 and 2037 (95th minus 50th Percentile)	• KY Power measures and considers the potential for customer costs to increase beyond expected levels due to market volatility or extreme weather in 2027 and 2037. • This metric compares the difference between annual portfolio costs under expected market conditions and annual portfolio costs under stochastically generated market conditions that reflect high-cost market events. • **A lower number is better**, indicating that the costs of the candidate portfolio rise less when short-term market conditions are erratic or unfavorable.
Market Exposure	2037 Purchases / Sales as % of Total Portfolio Demand in Summer and Winter	• KY Power measures and considers the reliance of each candidate portfolio on market sales or purchases to balance seasonal generation with customer load. • The metric reports net purchases or sales in 2037, distinguishing between market activity in the summer (June-Aug) and winter (Dec-Feb) seasons. • **Closer to zero** indicates less reliance on the market to meet energy needs

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Stochastic Analysis

The stochastic analysis tests each candidate resource plan under 250 random combinations of market conditions will be done and compared customer exposure to higher costs during periods of volatility.

IRP Stochastic Variables

Power Prices

- Hourly power prices may vary significantly during periods of extreme weather, peak conditions, or system outages
- Evaluating random draws of power prices – in combination with other variables – allows SWEPCO to test the robustness of candidate portfolios under volatile market conditions

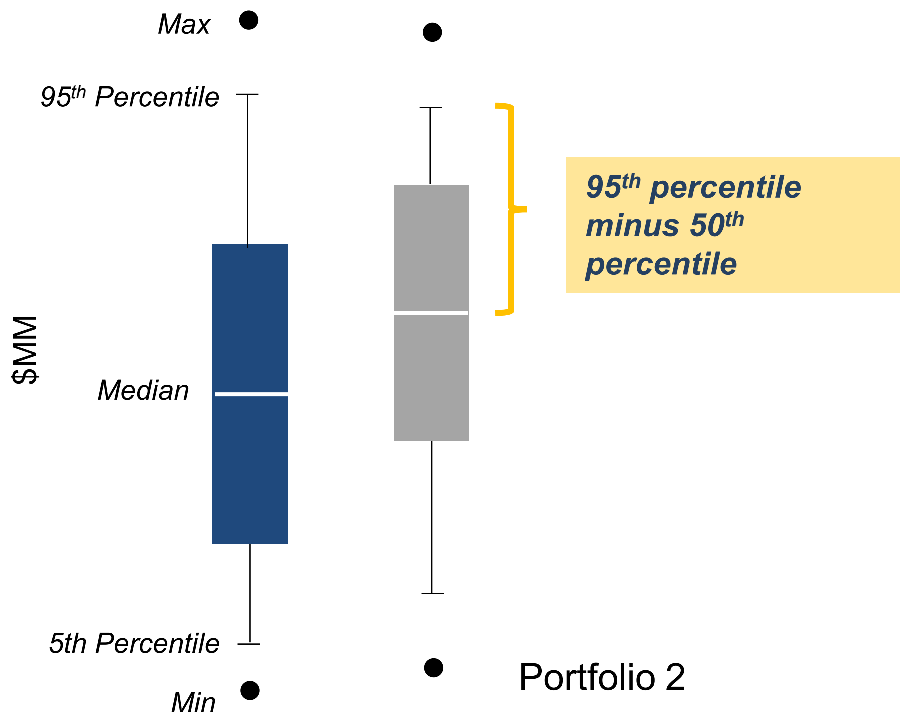
Natural Gas Prices

- Daily natural gas prices are highly variable depending on weather and broader system conditions that tighten in peak periods
- Natural gas fuel costs are expected to be an important component of total system costs under certain candidate resource strategies

Wind & Solar Output

- Hourly output from renewable generators can be highly variable and may fail to generate when customer demands are high or deliver too much energy when customer demands are low
- Certain candidate resource strategies select new renewable generation and evaluating variability in unit outputs allows SWEPCO to ensure rate stability and affordability are maintained for customers even as corporate sustainability targets are met

Measuring Cost Risk on the IRP Scorecard



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Objective: Maintaining Reliability

The Maintaining Reliability indicators compare the amount of excess reserves, the amount of dispatchable capacity in the fleet, and the technology diversity of the KY Power generating mix across candidate plans.

Performance Indicator	Metric	Description
Planning Reserves	Avg. Seasonal Reserve Margin % 2022-2037	• KY Power measures and considers the amount of average amount of firm capacity in each candidate portfolio over the next 15 years on a seasonal basis. • This metric is a composite calculated by averaging the winter and summer capacity position of each portfolio across all five market scenarios for years 2022-2037. • **A higher number is better**, indicating more reserves are available to meet PJM requirements.
Operational Flexibility	Nameplate MW of dispatchable units in 2027 and 2037	• KY Power measures and considers the total amount of dispatchable units added to the portfolio by years 2027 and 2037 to compare candidate resource plans. • The metric for this indicator is the total Nameplate MW of fast-ramping technologies included in the candidate resource plan. • **A higher number is better,** indicating greater ability to ramp generation up or down to react to market conditions and follow load.
Resource Diversity	Generation by technology type, % of total portfolio in 2037	• KY Power measures and considers the diversity of new technologies added to its portfolio when comparing candidate portfolios. • This metric is a pie-chart showing total generation by each technology type in year 2037. • **A less concentrated portfolio is better**, overreliance on a single technology exposes customers to performance risk when conditions for that technology are unfavorable.

Objective: Local Impacts & Sustainability

KY Power also considers Local Impacts and a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

Performance Indicator	Metric	Description
Local Impacts	Nameplate MW & Total CAPEX Installed Inside KY Power Territory by 2037	• KY Power measures and considers the amount of new capacity that can be located inside customer communities when evaluating candidate portfolios. • This metric compares the nameplate MW installed and the total capital investment expected inside KY Power's service territory under each plan from 2022-2037. • **A higher number is better**, indicating more opportunities for customer-sited resources and additional investment in local communities.
CO_2 Emissions	2027 & 2037 % Reduction from 2000 Baseline - Reference Case	• KY Power measures and considers the total amount of expected CO2 emissions of each candidate portfolio on the Scorecard. • This metric compares the forecast emissions of candidate portfolios in 2027 and 2037 under Reference Case market conditions with KY Power's actual historical emissions from the year 2000. • **A higher number is better**, indicating greater levels of emissions reductions have been achieved and customers are less exposed to potential future CO_2 costs.

Questions?

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- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
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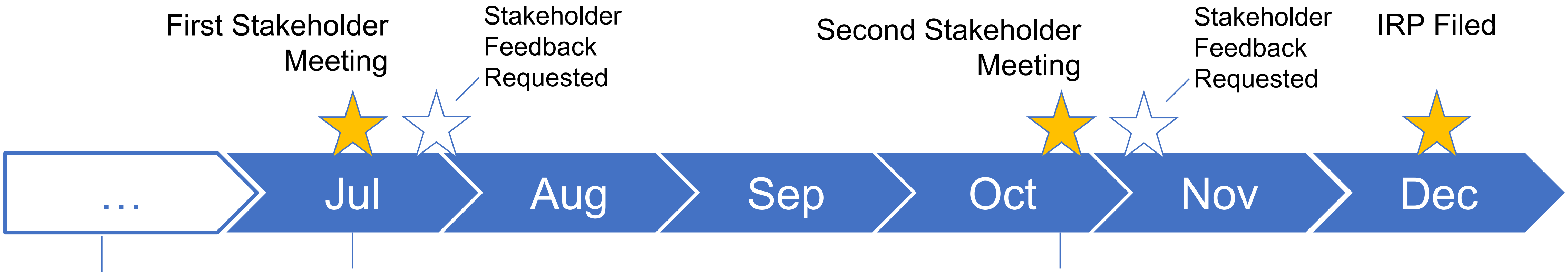
- Discussion & Closing Remarks

Stakeholder feedback is encouraged throughout the presentation

Thank You For Participating!

- KY Power requests that stakeholders provide written feedback by July 29th regarding:
  - The IRP Process and Objectives
  - The IRP Inputs and Market Scenarios
  - Development and Evaluation of Candidate Resource Plans
- Please contact kentucky_regulatory_services@aep.com with any additional questions.



<u>Key Tasks</u>
- Review 2019 Recommendations
- Perform Market Research
- Draft IRP Inputs Developed
- Market Potential Study Initiated
- Draft Scorecard Development

<u>IRP Inputs Meeting:</u>
- IRP Process and Objectives
- PJM Market Scenarios
- Portfolio Development
- The IRP Scorecard

<u>IRP Initial Findings Meeting:</u>
- Update on Stakeholder Feedback & Inputs
- Market Scenario Results
- Review of Candidate Portfolios
- Draft Scorecard & Initial Indicators

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2019 IRP Staff Recommendations by IRP Section

Section 2 – Load Forecasting

- Provide more detail explaining county-level data obtained from Moody's and the process used to forecast native load, provide a more detailed description of alternate Moody's scenarios
- Provide more details on how base case assumptions were changes to develop load forecast scenarios
- Describe economic development activities and impact on load and employment in the service territory
- Provide a comparison 2019 forecast to actuals for annual and seasonal peak forecast by class
- Include discussion and analysis of DERs potential and impacts on load, including BTM resources

Section 3 – Demand Side Management / Energy Efficiency

- Define and improve procedures to evaluate, measure, and verify actual costs and benefits of EE savings
- Scrutinize results of existing DSM programs' cost-effectiveness test, provide detailed support for future program expansions
- Evaluate marginal benefits and costs, including opportunity costs of VVO and DR programs
- Examine additional low-income programs that allow for wider participation
- Continue to monitor DG additions in the service territory

Section 4 – Supply-side and Demand-side Resource Assessment

- Provide detailed cost / benefit study demonstrating participation as an FRR vs RPM, discuss advantages of FRR to the company
- Conduct a separate FRR vs PJM cost / benefit study assuming Mitchell station is retired in 2028 and that is generates beyond 2028
- Explicitly discuss and demonstrate how winter capacity requirements are being satisfied over the forecast, including PCA's role
- Explicitly describe evaluation of including KY base generation merchant plants and how those costs compare to alternate resources
- Explain costs / benefits of acquiring renewables through PPAs vs ownership in support of any renewable capacity additions
- Explain costs associated with transmission upgrades needed to accommodate renewable capacity additions
- Model the impact of ELGs on the Mitchell Plant along with impacts to preferred plan and PJM / native capacity position
- Model scenarios with different renewable constraints and no constraints on size or addition
- If preferred plan options from 2019 IRP have not been pursued by the next IRP, provide a detailed explanation of why and modeling of alternate course taken

Section 5 – Integration and Plan Optimization

- Illustrate that the preferred plan meets native winter peaks in the next IRP, in addition to PJM summer peaks

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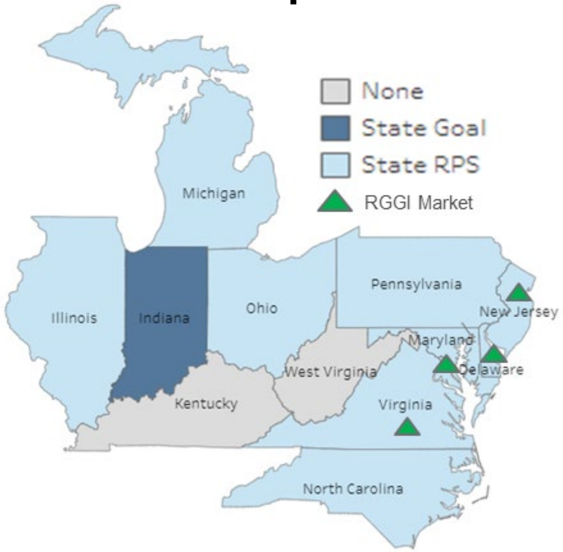
All 2022 IRP Market Scenarios incorporate impacts of regional policies in PJM

State RPS Requirements

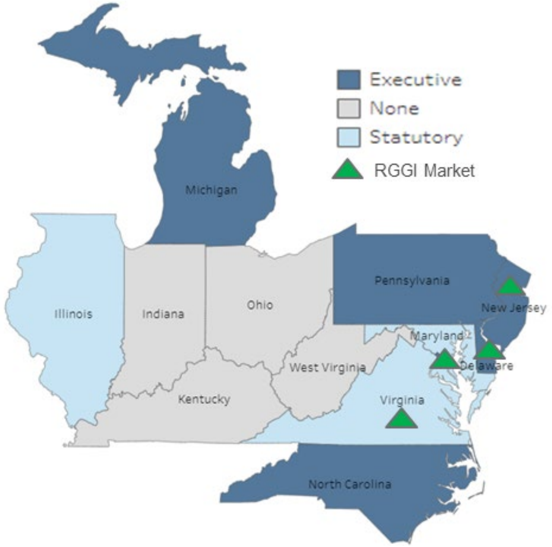


▲	**NJ:** 50% by 2030**	▲	**VA:** 100% by 2045/2050 (IOUs)
▲	**MD:** 50% by 2030**		**OH:** 8.5% by 2026
▲	**DE:** 40% by 2035		**MI:** 15% by 2021
	DC: 100% by 2032		**IN:** 10% by 2025***
	PA: 18% by 2021***		**KY:** -
	IL: 100% by 2032		**WV:** -
	NC: 12.5% by 2021 (IOUs)		

**Includes an additional 2.5% of Class II resources each year - *Class II refers to renewable resources that began operation before January 1, 1998*

***Includes non-renewable alternative energy resources

State Emissions Reduction Targets



▲	**NJ:** 80% by 2050	▲	**VA:** Net Zero by 2045
▲	**MD:** 40% by 2030		**OH:** -
▲	**DE:** 30% by 2030		**MI:** 26-28% by 2025
	DC: 50% by 2032*		**IN:** -
	PA: 26% by 2025*		**KY:** -
	IL: Net Zero by 2045		**WV:** -
	NC: 40% by 2025		

*Additional 80% reduction by 2050 target

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Kentucky Power 2022 IRP

IRP Stakeholder Meeting Material

January 25th, 2023

Agenda

- Welcome and Introductions
- Overview of the 2022 IRP Process
- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
- Market Scenario Results
- Portfolio Development & Results
- Portfolio Risk Analysis
- Scorecard Development
- Discussion & Closing Remarks

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Stakeholder feedback is encouraged throughout the presentation.

Housekeeping

COVID-19 Protocols (In Person Attendance)	Housekeeping (Virtual Attendance)
• We encourage appropriate precautions. • Facemasks are not required at this time, though please wear if you prefer. • Social distancing is recommended. • Frequent hand washing and hand sanitizer use.	• Microsoft Teams Meeting will be active during event. • Please mute your audio unless speaking. • Stakeholder feedback is encouraged throughout the presentation. • Chat window will be monitored.

Safety Topic

Speaker: Cindy Wiseman – Kentucky Power

KENTUCKY POWER

Company Overview - Who We Are

Headquartered in Ashland, Ky., Kentucky Power is one of seven operating companies owned by American Electric Power, which has a combined service territory spanning 11 states across America's heartland.

We provide service to approximately 165,000 retail customers in all or part of 20 eastern Kentucky counties. Kentucky Power's distribution operations work from service centers in Ashland, Hazard and Pikeville and from area offices in Paintsville and Whitesburg.

We are an electric company that believes the power to make a difference is in all our hands. When you connect with our service, you tap into a community resource that sustains life, achieves technological innovation and spurs economic growth. Together, with you, we create brighter futures and boundless opportunities in 20 counties on the eastern edge of the Bluegrass State.

Our connection to our community runs deep, and we continue to strengthen it by investing in issues that matter most to you and your family.

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Company Overview

Service Territory & Generation Resources

Key Facts

2021 Energy Sales	5,980	GWh
Avg. Annual Use per Residential Customer	14,791	kWh
Avg. Cost per kWh for Residential Customers	14.24	¢/kWh
Distribution Lines	10,051	miles
Transmission Lines	1,217	miles
Owned Generation	1,075	MW
2021 Total Customer Count		
Residential	133,805	
Commercial	30,532	
Industrial	1,079	
Combined Rate Base as of 12/31/2021	~2.0 billion	$
KPCo Senior Unsecured Credit Rating	Baa3 / BBB+	

Note: The Rockport UPA for 393 MW expired on 12/7/22. On 12/31/28, Kentucky Power will no longer have an interest in the Mitchell Plant.

About CRA

CRA International

- 780 Consultants
- 23 Offices in 9 Countries
- 15 Practice Areas
- Founded in 1965

Energy Practice Offices

Boston
New York
Washington DC
Toronto
London
Munich

Energy Practice Offerings

Corporate Strategy

Corporate Scenario Development & Analytics

Portfolio Optimization

Offering Development

M&A / Growth Strategy

Market Entry Strategy

Resource Strategy & Investment Planning

Integrated Resource Plan

Grid Modernization

Utility of the Future

Infrastructure Planning

Storage Assessments

Rate Impact Analysis

Market Analysis & Design

Power and Gas Market Forecasts

Market Based Rate (MBR) filings

FERC Analysis (Order 841, Order 1000)

Capacity Market Design

RTO Cost Benefit Analysis

Transaction & Restructuring Support

Energy Assets Due Diligence and Valuation

Company Restructuring

Competitive Merger Reviews

Utility M&A Due Diligence

Regulatory and Litigation Support

FERC and State Ratemaking

Damages Analysis

International Arbitration

Commercial Litigation

Expert Testimony

Resource Planning Work for Utilities

CRA has supported many IOUs and POUs with strategy and investment planning.

Client examples from the last 3 years

NiSource

- 2018, 2021 IRP
- Responsibility for inputs development, modeling, stakeholder engagement
- Regulatory testimony in rate case and CPCN proceeding
- Also led energy procurement

Dominion Energy

- Dominion South Carolina 2020, 2021, 2022 IRP
- Responsibility for process validation and stakeholder engagement
- Regulatory testimony development

American Electric Power – Boundless Energy

- Supported 2021 IRP development for SWEPCO and PSO
- Responsibility for inputs development, market and portfolio modeling, drafting of IRP reports and stakeholder materials

Alliant Energy

- 2019-2021 Clean Energy Blueprint and IRP development for WI and IA
- Responsibility for inputs development, modeling, stakeholder engagement
- Regulatory testimony in rate case and CPCN proceeding

Liberty

- Developed 2019 IRP for Empire District
- Responsibility for analyzing resource options and evaluating generation portfolios
- Oversaw stakeholder engagement activities and presentation of IRP analysis

Minnkota Power Cooperative – A Touchstone Energy® Cooperative

- 2021 resource plan
- Responsibility for inputs development, modeling, Board engagement
- Company is evaluating carbon capture and sequestration

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Agenda

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IRP Purpose

The purpose of the IRP	Requirements
• Provide a roadmap at a point in time that utilities and load serving entities use as a planning tool when evaluating resource decisions necessary to meet forecasted electric capacity and energy demand requirements in a balanced approach.	• Meets the requirements of 807 KAR 5:058 and Kentucky Public Service Commission (Kentucky PSC or Commission) Staff recommendations provided in the Staff Report on Kentucky Power's 2019 Integrated Resource Plan. • An IRP is conducted every 3 years, evaluating resource needs over a 15-year planning period.

Review of the 2022 IRP Process, Roles, and Responsibilities

Overview of 2022 IRP Responsibilities

Kentucky Power

- Sets Objectives & Performance Criteria
- Provides Load and Demand-side Assumptions
- Manages Regulatory Process

CRA

- Develops Supply-side Assumptions
- Develops Market Scenarios & Inputs
- Develops Candidate Resource Portfolios
- Populates Scorecard

Kentucky Power

- Evaluates Resource Alternatives
- Selects Preferred Plan for 2022 IRP
- Develops Short-term Action Plan

2022 IRP Analysis Steps

Define IRP Objectives Aligned to Customer Needs

⇩

Model Market Scenarios to Test Future Risks

⇩

Develop Candidate Portfolios of Demand and Supply Side Resources

⇩

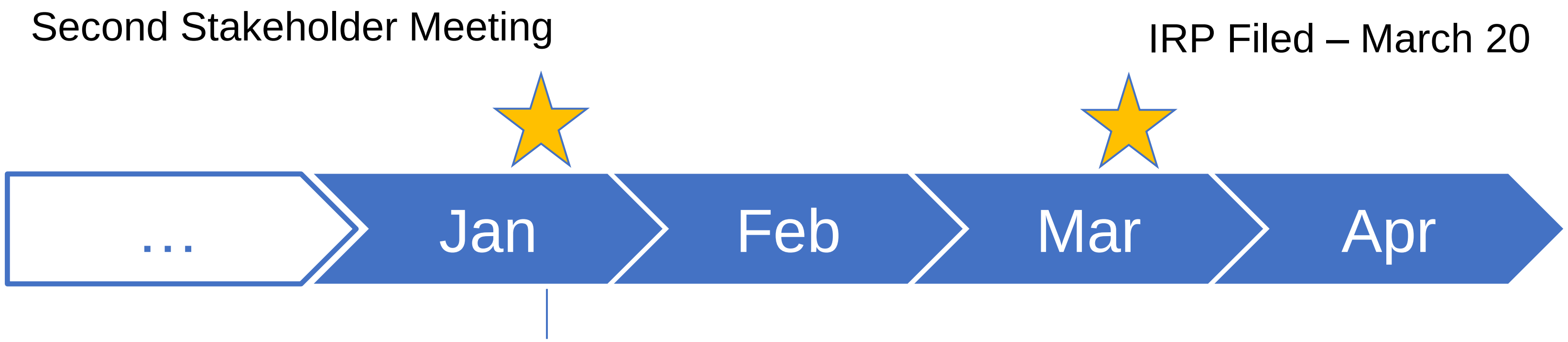
Test Portfolios across Scenarios & Stochastic Risks

⇩

Compare Results on the Scorecard & Select the Preferred Plan

Feedback & Stakeholder Process

- Kentucky Power has considered and integrated feedback from both the 2019 IRP and the July, 2022, stakeholder meeting throughout this IRP process
  - Key highlights
    - 2019 IRP – analyzed performance to a winter capacity position
    - July Stakeholder meeting – Included multiple tiers of renewable resource costs, evaluated a broad spectrum of resource types, including energy efficiency resources to meet the Company's obligations, modeled market purchases to bridge the time needed to bring firm resources online and analyzed the continued operations of Big Sandy beyond 2030
- Further stakeholder feedback is requested and considered as the Company identifies its Preferred Plan



<u>IRP Initial Findings Meeting:</u>
- Review Modeling Inputs
- Market Scenario Results
- Review of Candidate Portfolios
- Draft Scorecard & Initial Indicators

Questions?

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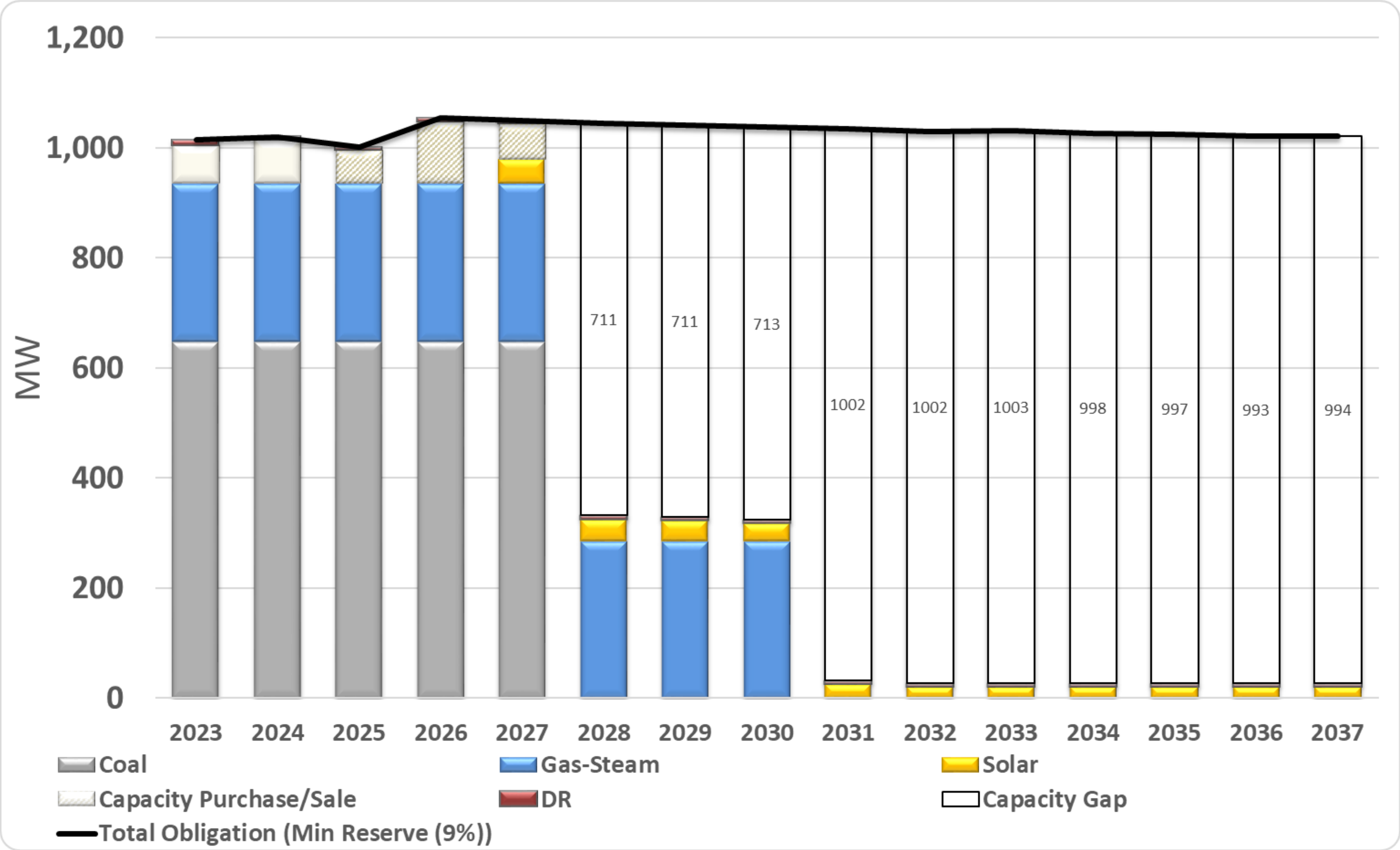
KENTUCKY POWER

2022 IRP Starting Capacity Position



The loss of Mitchell after 2028 and Big Sandy after 2030 leave Kentucky Power with a significant gap after the Rockport UPA expired in 2022

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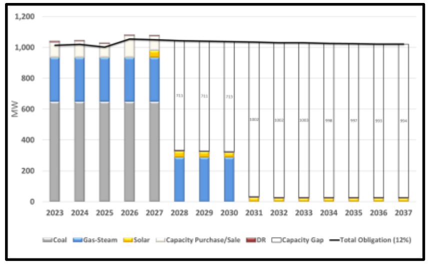
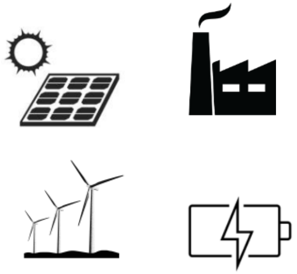
Selection of the Preferred Plan

Going in View



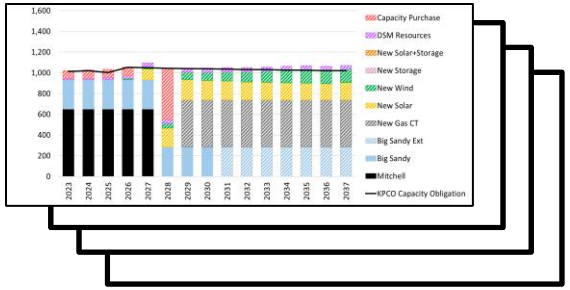
The going in positions shows a need for new capacity to meet Kentucky Power customer requirements

Resource Options

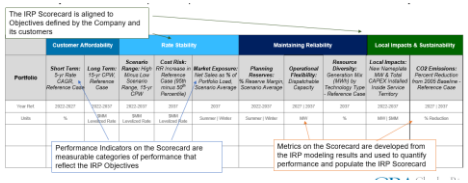


Kentucky Power used AURORA to evaluate resource options under different market conditions and test specific strategies

Candidate Portfolios



Scorecard



The resulting set of portfolios is evaluated against the IRP Scorecard to identify a preferred plan that maintains reliability and best maintains affordable and stable rates while also achieve emissions reduction targets

Kentucky Power evaluated five candidate portfolios against the IRP Objectives but has not yet selected a Preferred Plan. Following this Stakeholder Conference and additional Stakeholder feedback, Kentucky Power will select the best combination of supply- and demand-side resources that meet customer needs and satisfy the IRP Objectives.

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Proposed 2022 IRP PJM Market Scenarios

Reference Scenario

- The PJM market continues to evolve based on the current outlook for load growth, commodity prices, technology development, and regulatory pressure.

Reference Scenario with Higher Unit Costs [Sensitivity]

- The PJM market continues to evolve based on the current outlook for load growth, commodity prices, and regulatory pressure. New unit costs remain elevated as short-term shocks to the supply chain are not fully resolved over the forecast period.

Clean Energy Technology Advancement

- Extension of federal renewable tax credits (and expansion to storage) and continued technology improvements result in low technology costs for new wind, solar, and storage. Widespread adoption of EVs and electrification results in high load growth.

Enhanced Carbon Regulation

- Carbon emissions are regulated through a federal carbon cap and trade program that results in a significant CO_2 price and a long-term power sector net zero trajectory. Higher natural gas prices due to production restrictions.

No Carbon Regulation

- Natural gas pricing revert to lows observed in recent years, this combines with no federal carbon regulation to provide more favorable market conditions for gas and coal resources vs. renewables relative to the Reference Case

All 2022 IRP Market Scenarios incorporate impacts of regional policies (RGGI, RPS) in PJM

The PJM Market Scenarios Combine Multiple Fundamental Elements

	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Slower Decline
3	Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Faster Decline
4	Enhanced Carbon Regulation (ECR)	Low	High	High	Faster Decline
5	No Carbon Regulation (NCR)	Base	Low	No Price	Base

Note – IRA provisions implemented in all scenarios

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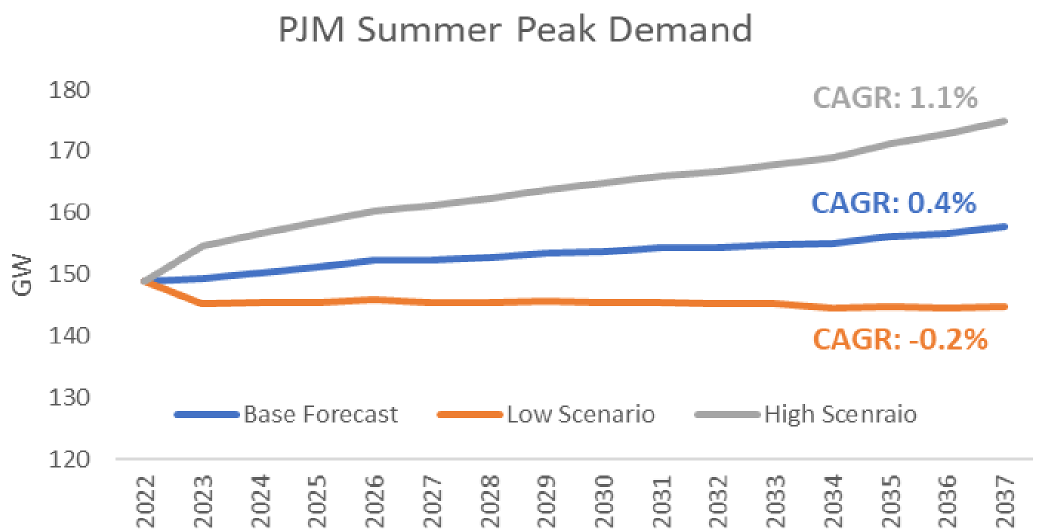
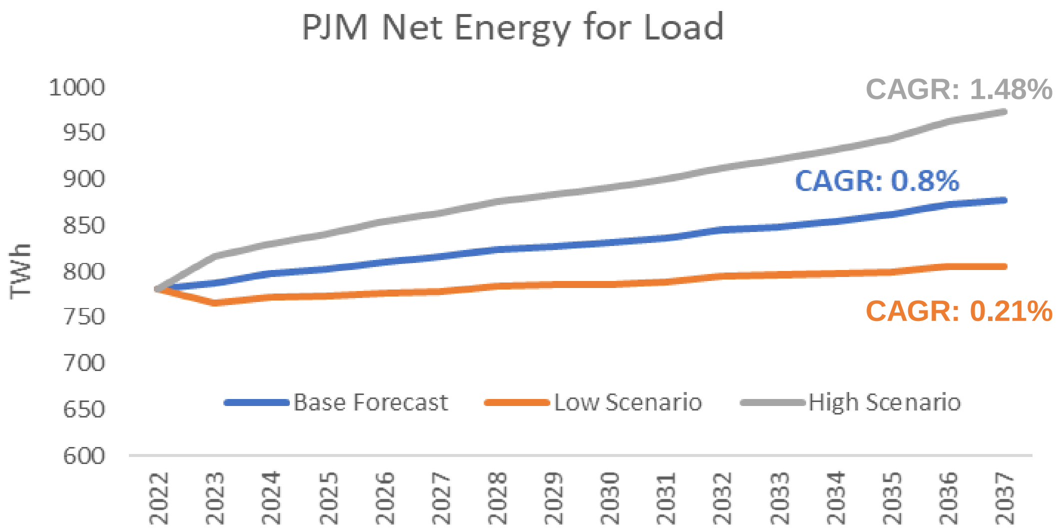
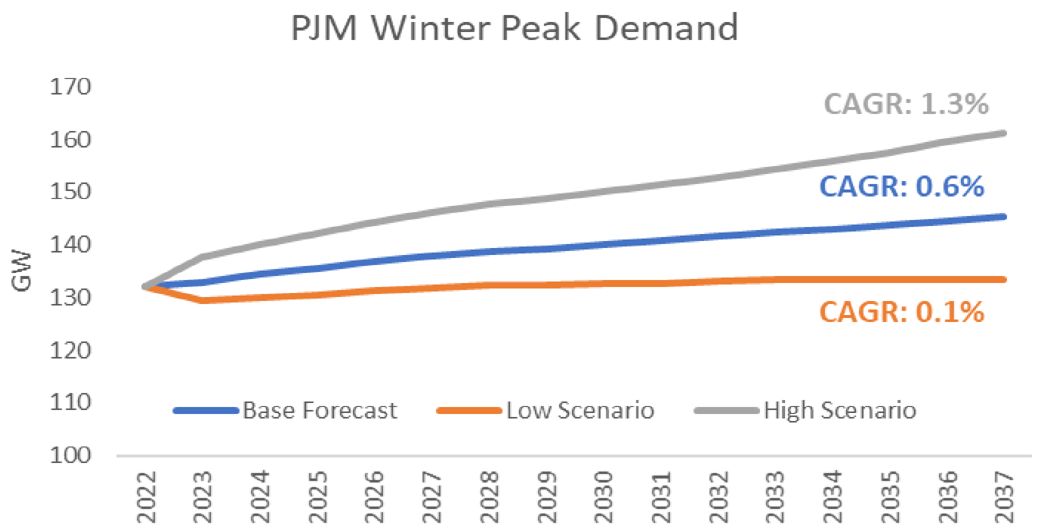
PJM Load Forecast

- For **PJM market modeling**, CRA relies on the latest forecasts provided by the RTO as the "Base" view for scenario modeling
    - The PJM 2022 outlook was the latest available at the time of modeling







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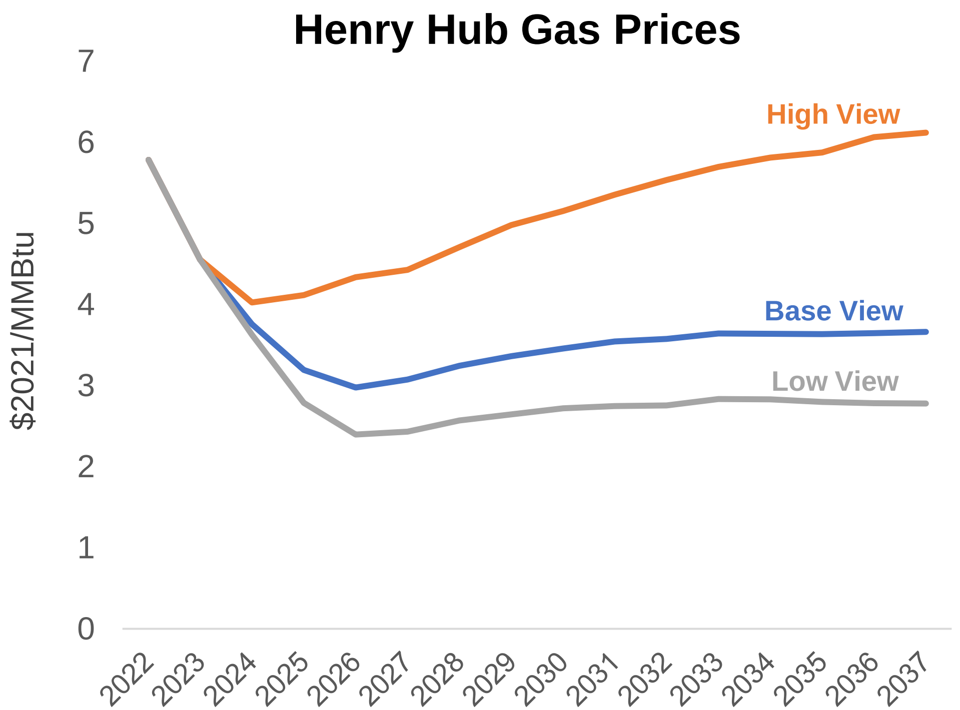
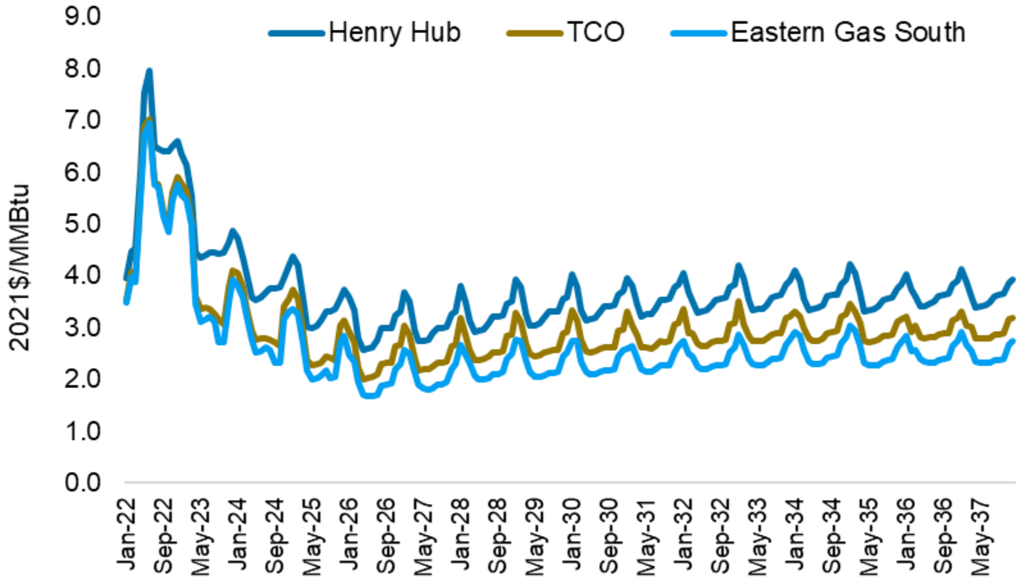
Natural Gas Price Ranges



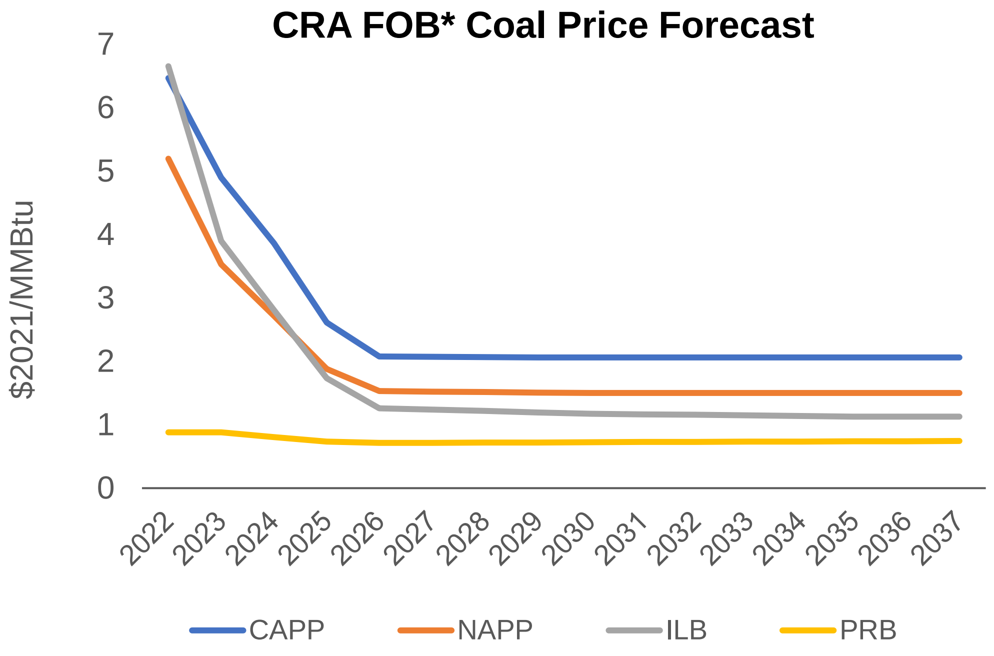


- Kentucky Power sets the range of long-term gas forecasts using EIA's 2022 Annual Energy Outlook forecasts
- Over the first 4 years, recent market data informs expected prices, blend into the AEO views

- In the Market Scenarios, seasonal prices and regional basis are forecast for key market hubs
- Natural gas prices include daily volatility

Coal Price Inputs

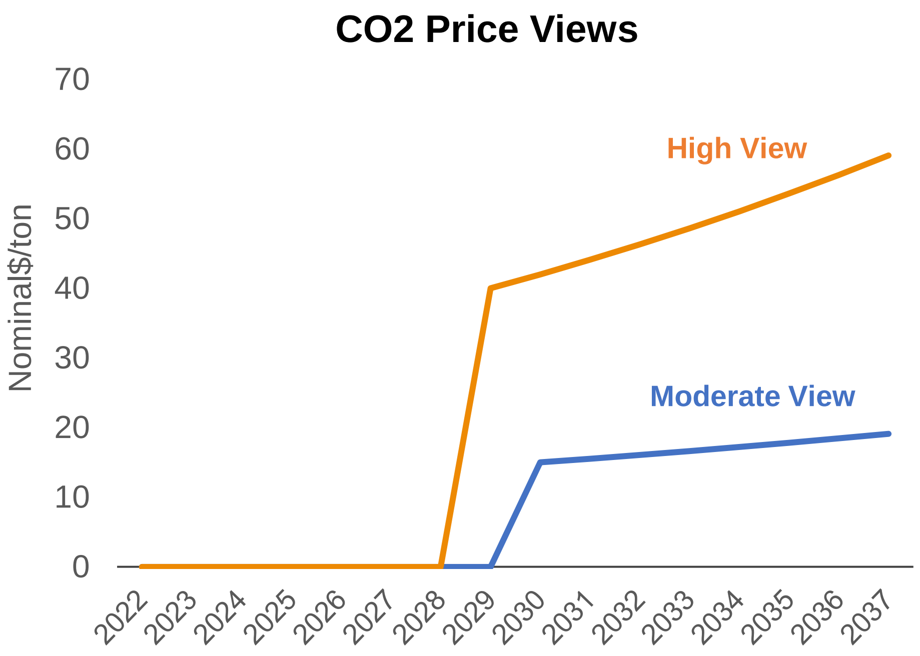
- U.S. coal prices exhibit flat-to-declining trends over the long-term due to continued coal retirement expectations in the US
- Over the long term, U.S. domestic demand for coals is expected to decline significantly, in proportion to the projected declines in U.S. demand for coal-fired generation throughout the forecast period



*The Free On Board price represents the value of coal at the coal mine and excludes transport and insurance costs

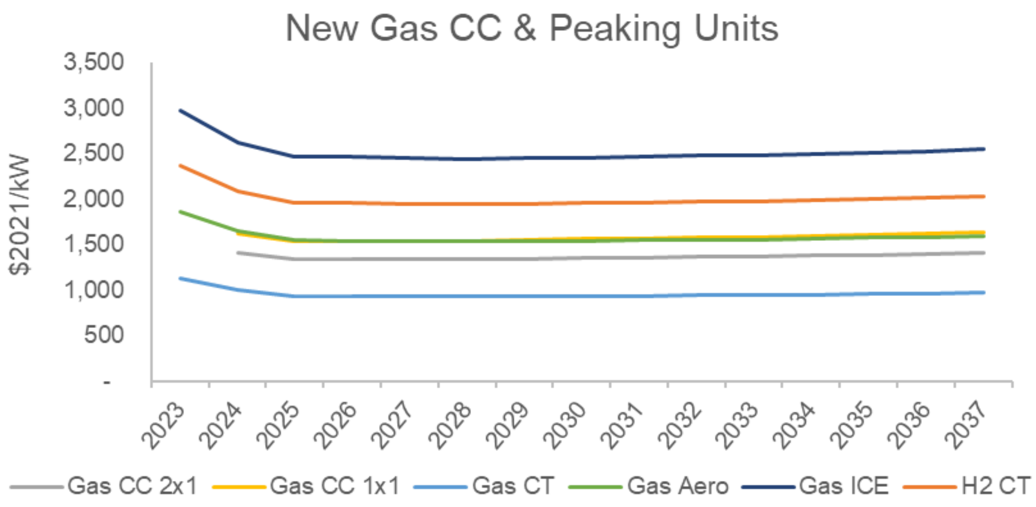
Carbon Price Inputs

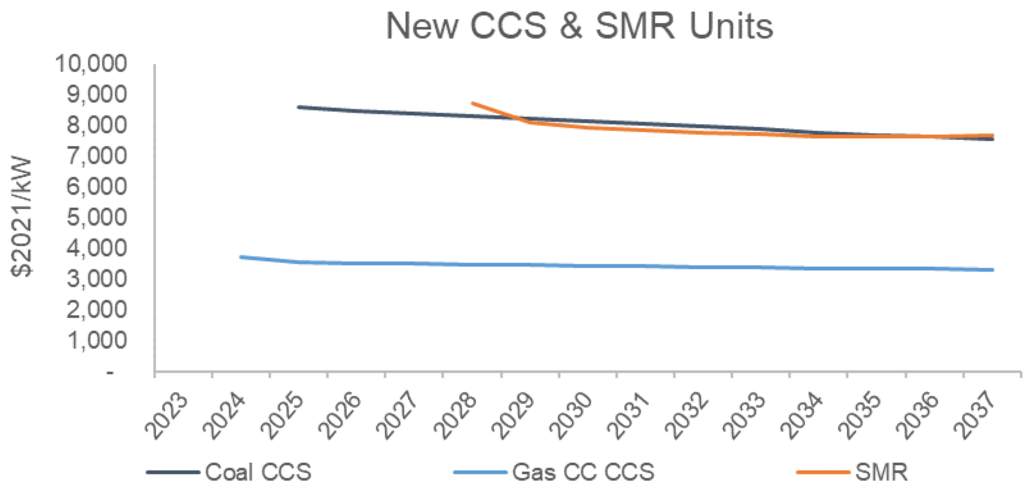
- CO_2 prices are assumed to be first implemented in 2030 for the Moderate View and in 2029 for the High View.
- The High view assumes that policymakers take more aggressive action to reduce CO_2 emissions over the short term, and trends toward towards the price needed to achieve net-zero reductions in 2050
- The Moderate view reflects the long-term trajectory needed to achieve modest (e.g., 70%) electric-sector emissions reductions by 2050

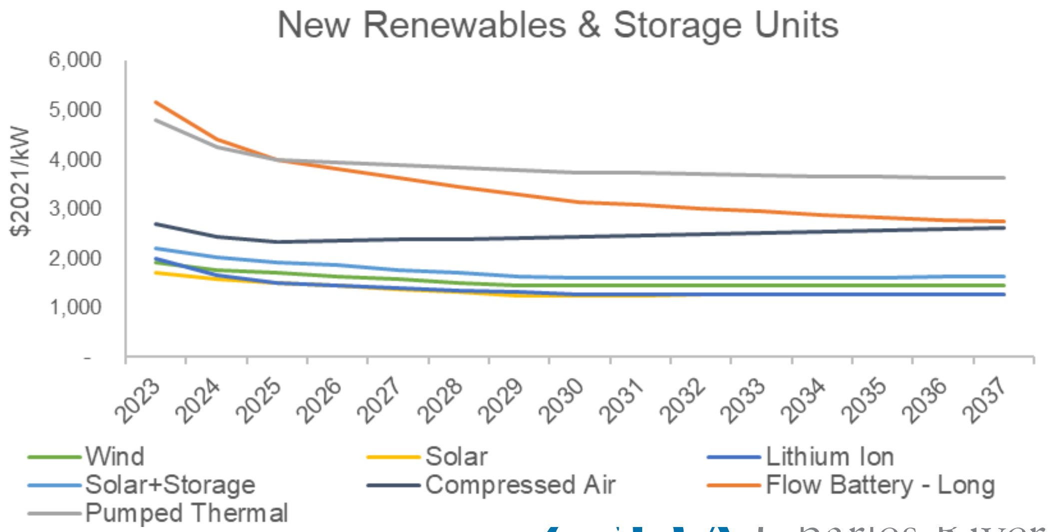


Utility-Scale Capital Costs

- Kentucky Power relies on publicly available sources to estimate the cost of new utility-scale resources
- New unit cost forecasts include declines on the basis of technology learning







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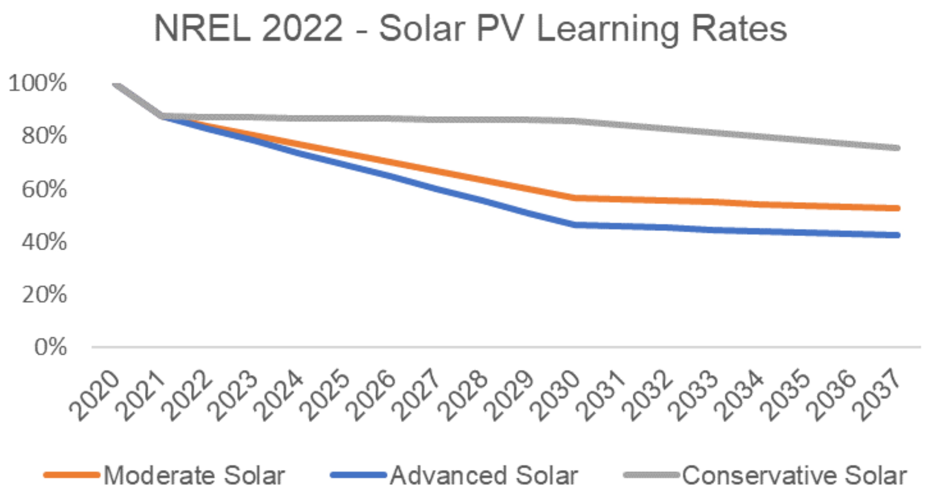
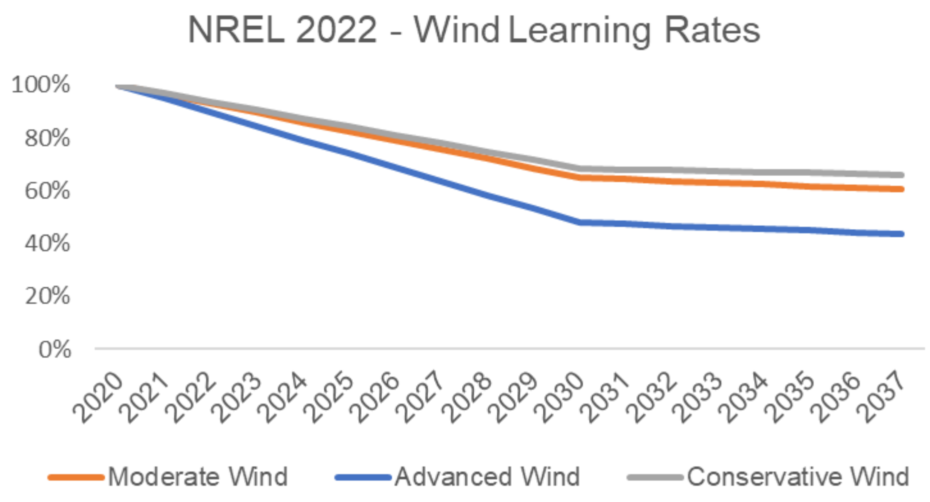
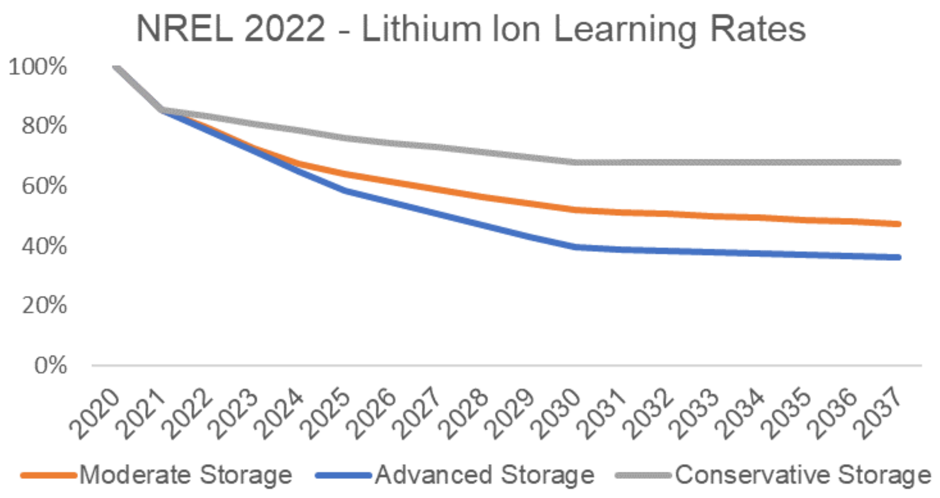
New Unit Cost Ranges

- Under the “Base” and “Faster Decline” technology cost views, the cost of new units declines to align with NREL “moderate” and “advanced” forecasts over the medium-term.
- Under the “Higher” technology cost sensitivity, Kentucky Power will test the risk that high costs will persist.
  - The transition from elevated pricing will take longer in this sensitivity, and future learning will follow NREL’s “conservative” forecast of technology cost improvement.







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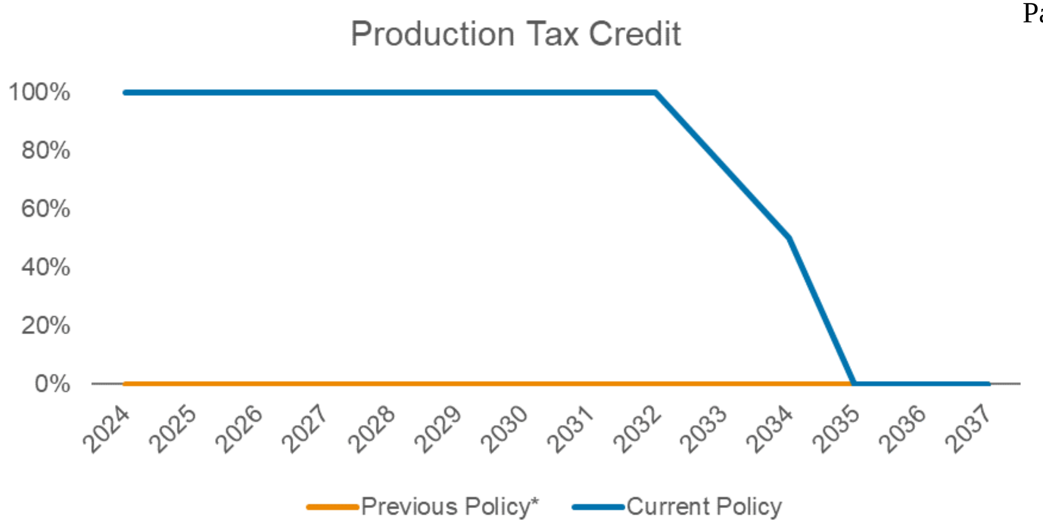
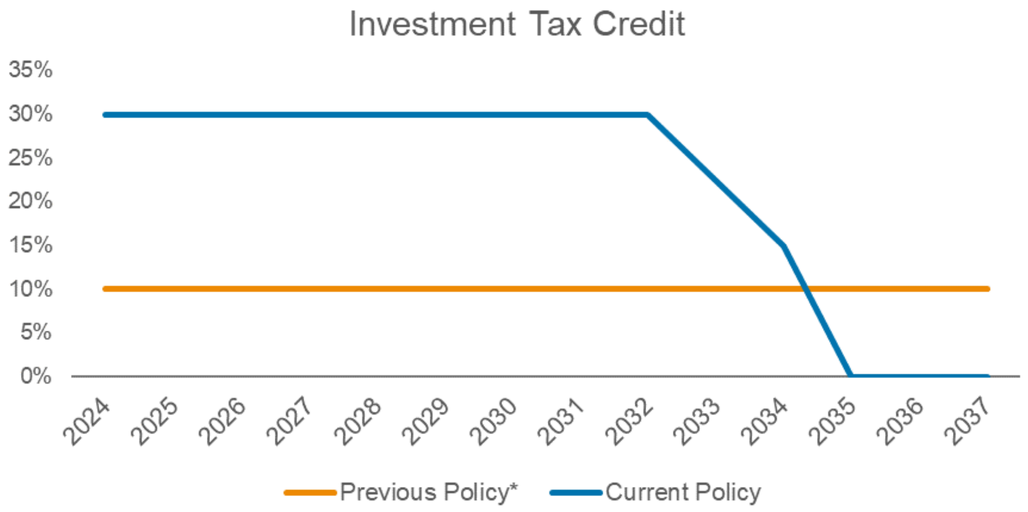
Outlooks for PTC / ITC extension

- The Inflation Reduction Act (IRA) was signed into law on August 16, 2022.
- IRA introduced extension of ITC and PTC to all non-emitting resources starting in 2025, phasing down in 2032. ITC available for storage.
- Under all scenarios, CRA assumes that the value of Federal tax credits declines or expires based on the current law.
  - See appendix for more detailed information regarding tax credit timelines.
- For portfolio modeling, a safe harbor provision is assumed for new resources for three years.





* Under "Relief Bill" passed on December 21, 2020

figures reflects unit online year

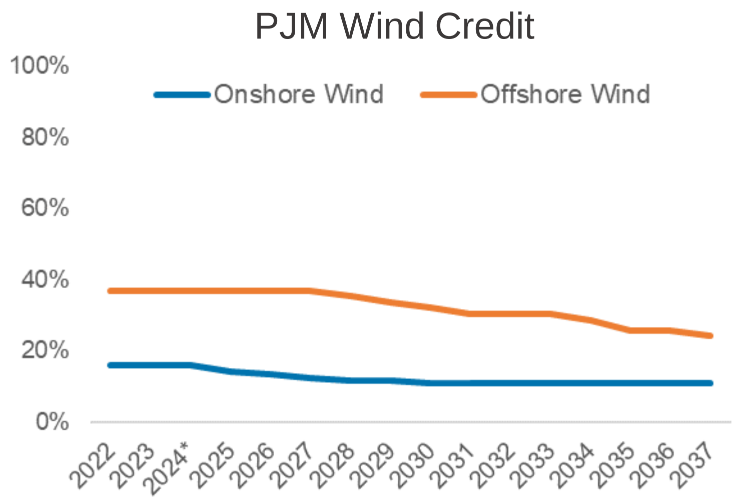
Reserve Requirement and Peak Credit Inputs

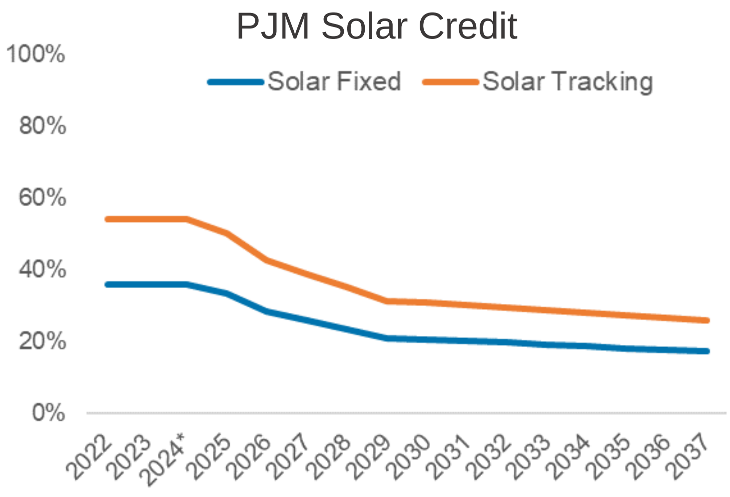
Reserve Requirements

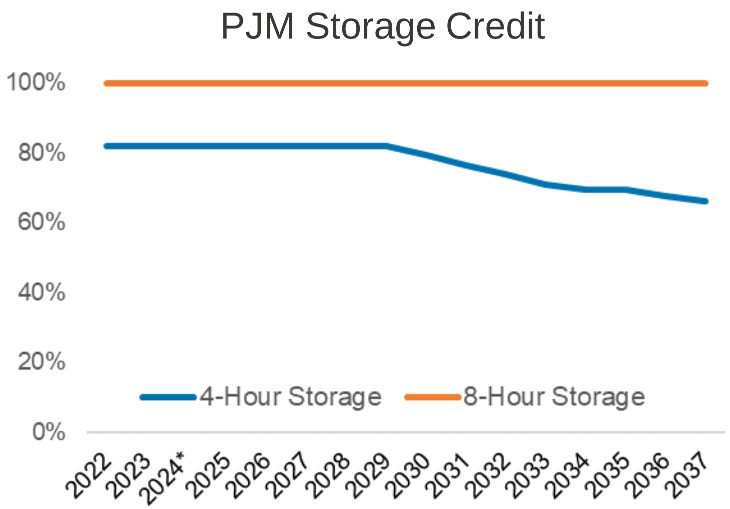
- PJM's Installed Reserve Margin (IRM) target is between 14.7-14.9% above summer peak load for the upcoming planning years. CRA modeled this requirement as a firm constraint on the PJM market model for the LTCE runs.

Summer Peak Credit

- Summer peak credit of incremental solar, wind and storage additions decline over time as more ELCC resources are added to the system.







** In 2024, the ELCC values reflect PJM's 2024/2025 Base Residual Auction ELCC class ratings. Beyond 2024, assumed ELCC values reflect preliminary capacity expansion in PJM region.*

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Note – IRA provisions implemented in all scenarios

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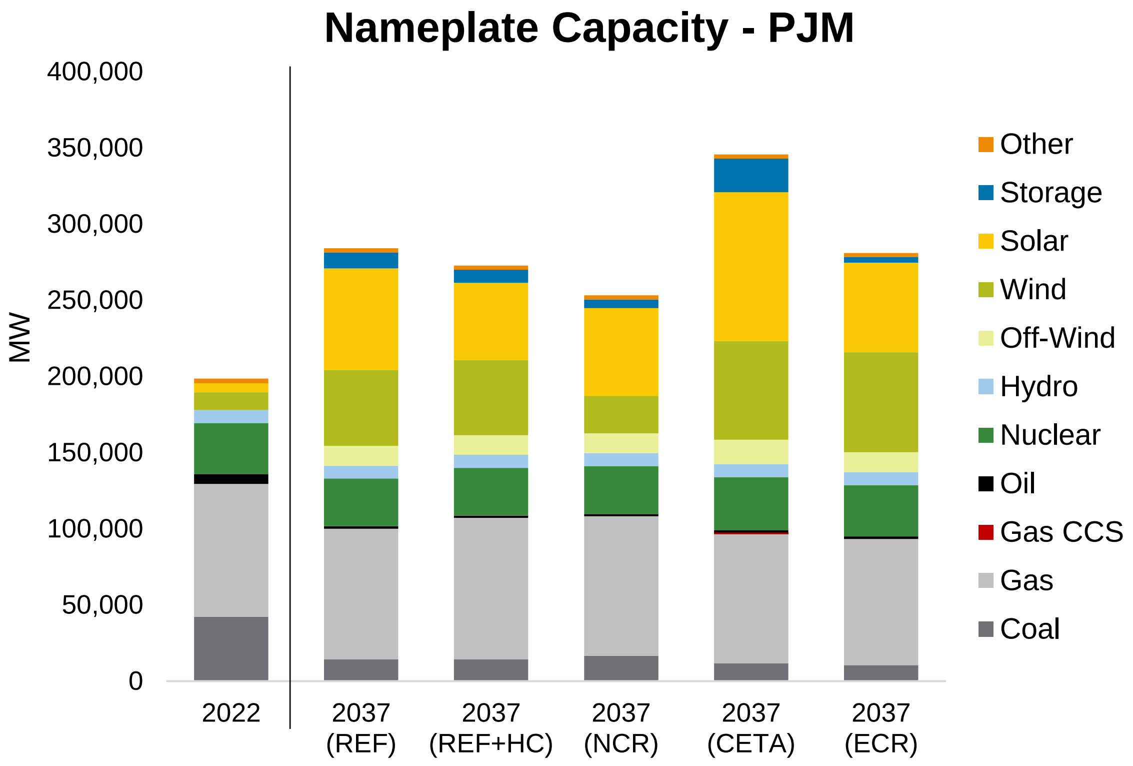
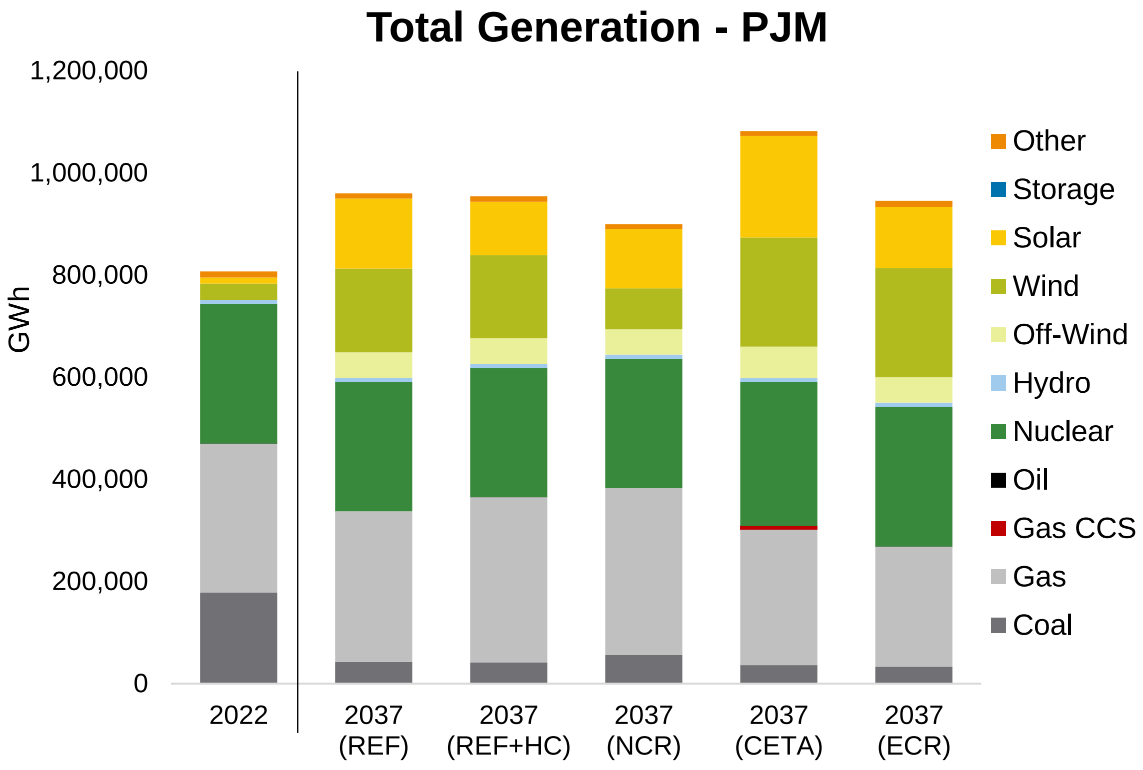
Scenario Results – PJM Supply Mix

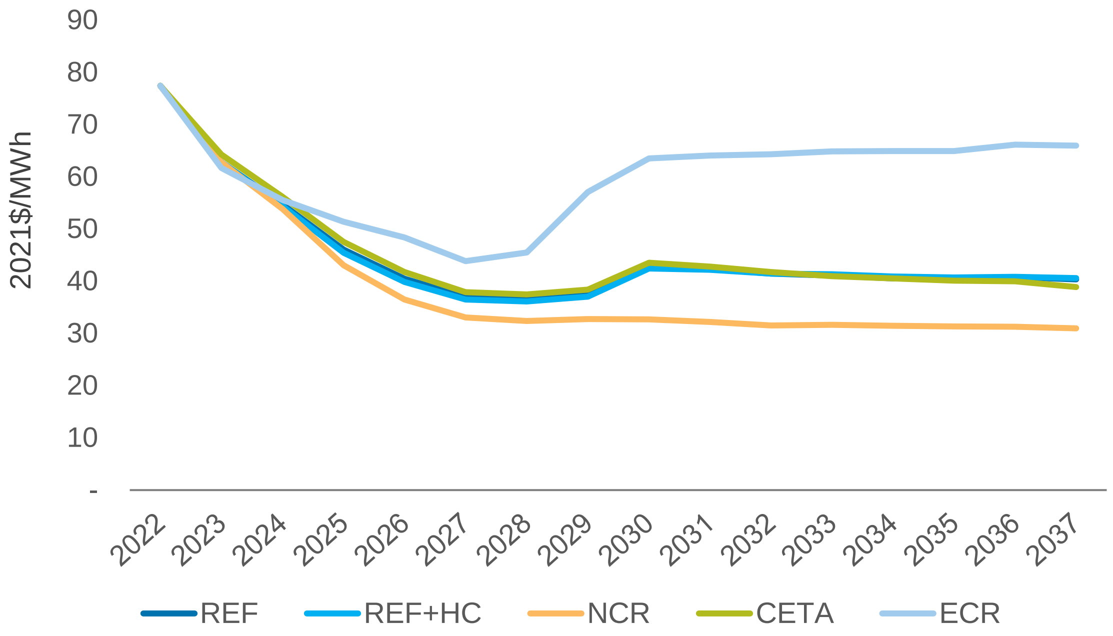




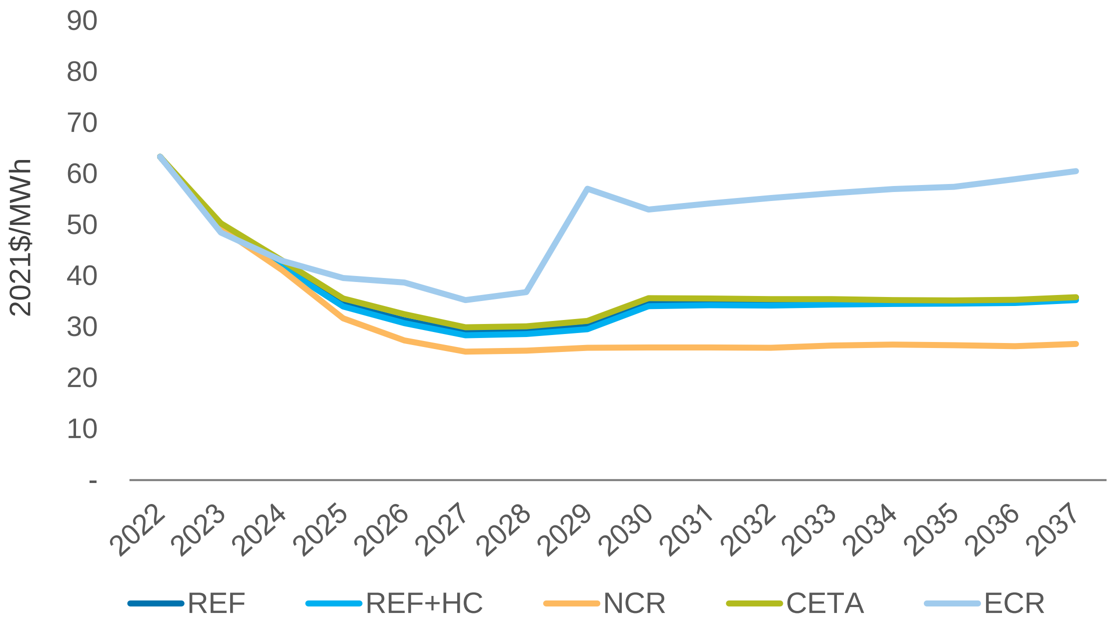
- Under all scenarios, coal capacity declines while the share of gas capacity remains steady in all but the ECR and CETA scenarios
- New additions are focused on wind, solar PV, and 4-hr battery storage, with small amounts of SMR and gas CCS are selected under the CETA scenario
- By 2037, renewable resources provide roughly 37% of total PJM generation in the REF scenario
- NCR has the lowest renewable generation, at 27% of total PJM output by 2037
- Natural gas and Nuclear dominate the generation mix by 2037, with more than 50%, across all scenarios

Scenario Results – PJM Market Prices

On-Peak Power Price
PJM AEP Zone



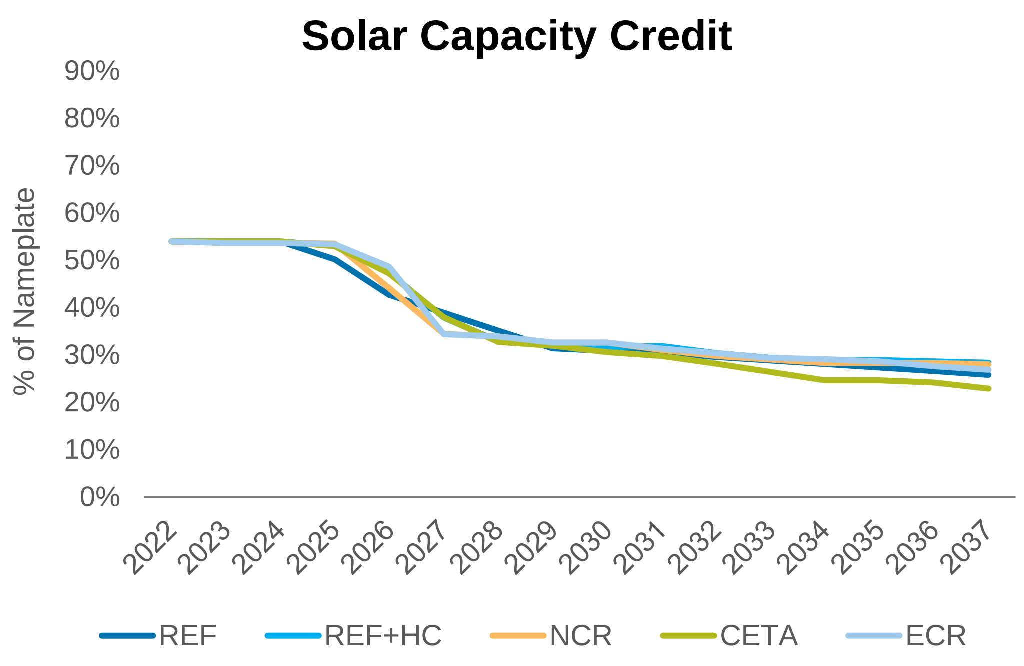
Off-Peak Power Price
PJM AEP Zone

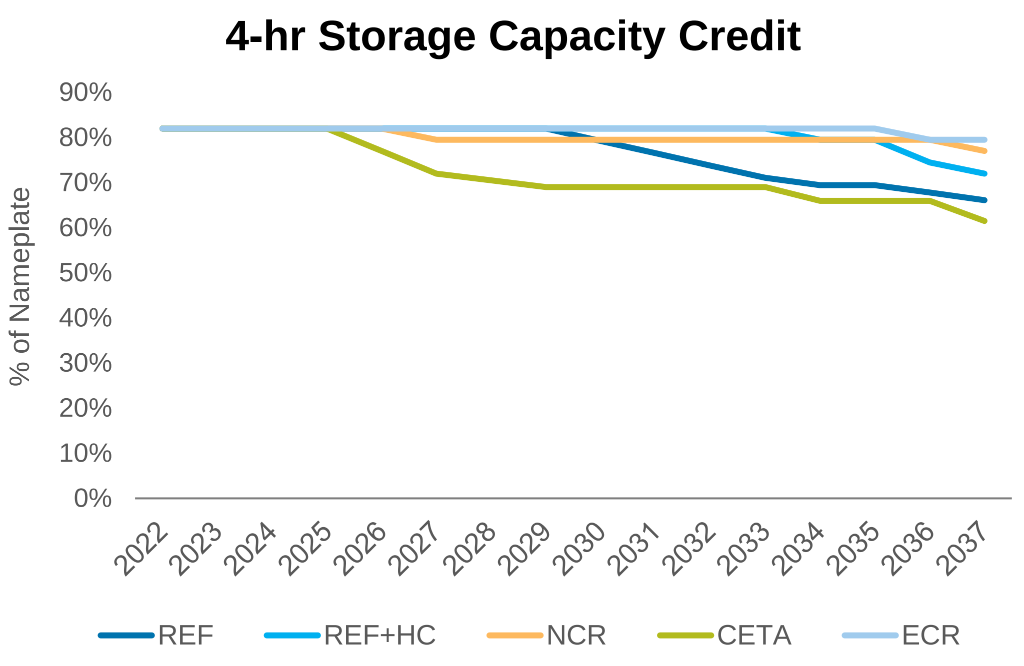


- Under the REF, REF + High Cost, and CETA scenarios, On-Peak prices decrease from current levels until the CO2 price is introduced in 2030, leading to a step-up in prices that hold steady around $40/MWh
- On-Peak prices are lowest in the NCR scenario due to the combination of low gas prices and zero CO2 price and are highest in ECR scenario, reflecting higher gas and CO2 prices

- The spread between On- and Off-Peak prices in the REF, REF + High Cost, and CETA scenarios start around $14/MWh in 2022, but tightens to around $5/MWh by 2037
- Similar results are observed in the remaining scenarios, with the addition of new renewable resource and storage tending to drive the convergence between On- and Off-Peak prices

Scenario Results – Solar and Storage Capacity Credit (Summer ELCC)

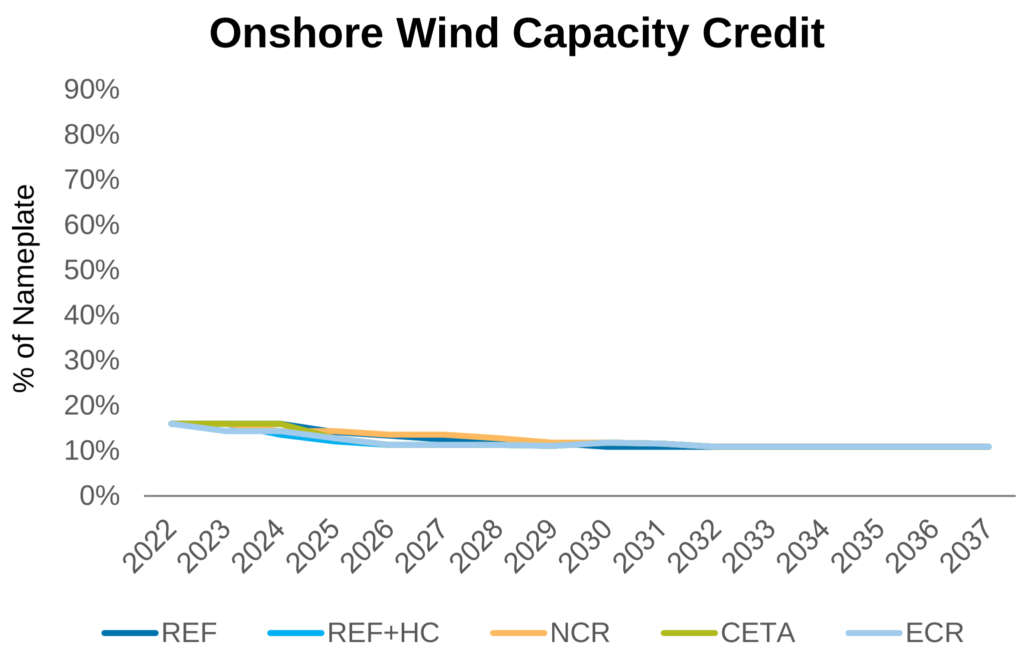


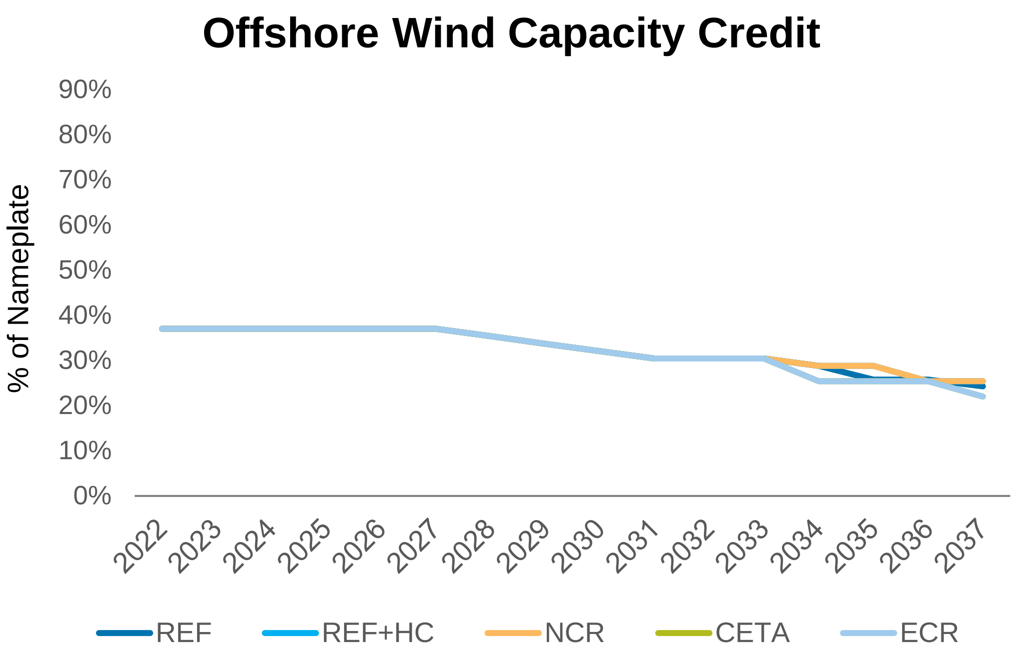


- Under the REF and ECR cases, solar peak credit declines from 54% currently to 26% by 2037
- Under CETA, rapid deployment of new renewables results lower solar peak credit values starting 2031
- Under the NCR Scenario, lower gas prices and lack of CO2 pressure reduce PJM-wide installations, resulting in higher solar peak credit values

- In the REF scenario, the peak credit of 4-hr Battery Storage falls from 82% currently to about 66% by 2037
- Under the CETA scenario, rapid deployment of 4-hr battery storage units results in a faster peak credit decline
- In the NCR scenario, less 4-hr battery storage is deployed across PJM resulting in higher peak credit after 2030

Scenario Results – Onshore and Offshore Wind Capacity Credit

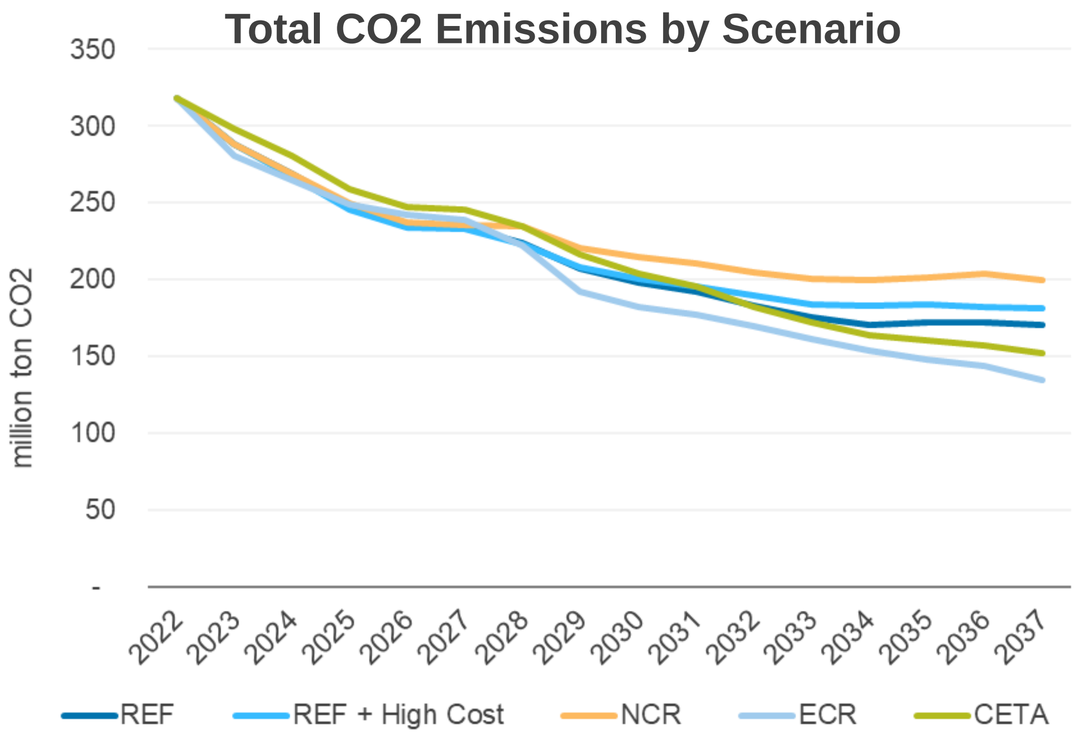




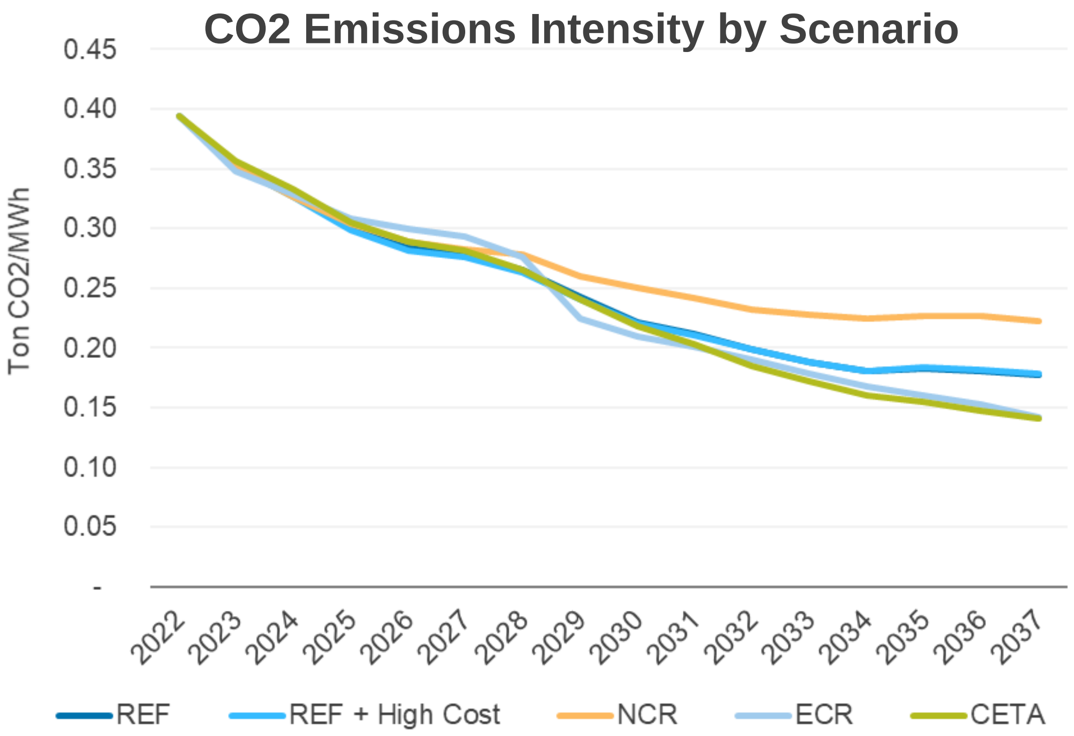
- Across almost all scenarios, Onshore Wind peak credit declines from 16% currently to 11% by 2037
- Under the NCR scenario, lower gas prices and lack of CO2 pressure reduce PJM-wide wind installations, resulting in slower wind peak credit decline between 2024-2030

- Among all scenarios, the peak credit of Offshore Wind declines from 37% currently to 23% by 2037
- Under the CETA & ECR scenarios, faster deployment of renewable resources results in a faster Offshore Wind peak credit decline after 2033

Scenario Results – CO_2 Emissions



- Across all scenarios, total CO2 emissions decline over the outlook period
- Under the REF scenario, total CO2 emissions decline by 47%, while only by 37% in the NCR scenario due to higher gas-fueled generation
- The ECR scenario exhibits faster reduction, at 58% by 2037, due to a combination of lower load and carbon prices



- Under the CETA scenario, emissions intensity is lowest by 2037, although with comparatively higher absolute levels than ECR, due to higher load

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Questions?

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IRP Portfolios are developed and evaluated using the Market Scenarios

IRP Scenarios Determine Market Prices, Tech Costs, Load & ELCC Inputs


Reference Scenario


Reference Scenario with Higher Unit Costs


Clean Energy Technology Advancement


Enhanced Carbon Regulation


No Carbon Regulation

CRA Develops Resource Alternatives to Test Under Market Scenario Conditions

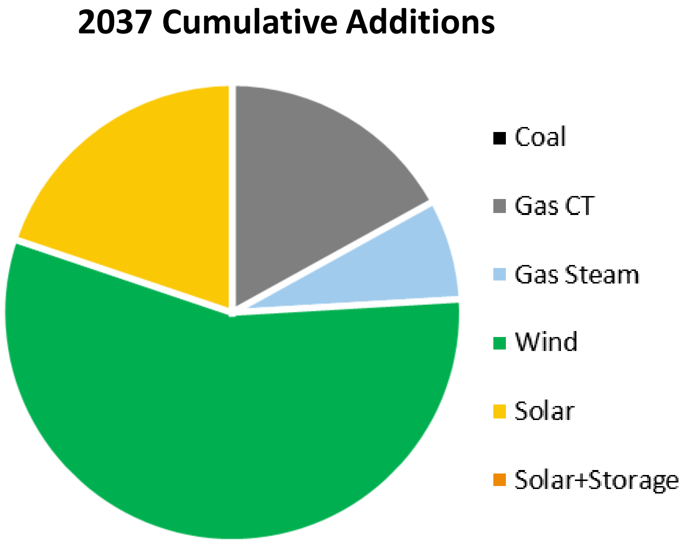
Demand-Side Options:

- Energy Efficiency

Supply-Side Options:

- Wind and Solar PV
- Gas-fired CTs and CCs
- 4hr-Battery Storage
- Hydrogen-fired CTs
- Advanced Nuclear & Storage

AURORA Selects the Least-Cost Combination of New Resources



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Energy Efficiency (EE) Benchmarking

- EE Savings inputs for the IRP are based on the results of a benchmarking exercise of recent market potential studies (conducted by GDS) in Indiana (AEP) and Kentucky, as well as reported EE utility data from EIA (Form 861).
- The benchmarking suggested EE savings of approximately 1% of annual sales as a reasonable target
  - *Assumed ramp up from 0.4% to 1% of all sales over the next four years*
  - *Assumed only 25% of industrial sales would be eligible for EE programs due to opt-out eligibility.*
- Costs were based on bench-marking exercise as well; leveraged recent potential studies to calculate the utility costs and total resource cost per unit of energy saved ($/MWh) .

Incremental Annual Savings (MWh)	2023	2024	2025	2026	2027-2042
Residential	0.50%	0.70%	0.95%	1.20%	1.20%
Commercial	0.50%	0.70%	0.95%	1.20%	1.20%
Industrial	0.25%	0.40%	0.55%	0.70%	0.70%
Total (Eligible Sales)	***0.47%***	***0.66%***	***0.90%***	***1.14%***	***1.14%***
Total (All Sales)	***0.40%***	***0.59%***	***0.81%***	***1.02%***	***1.02%***

EE Bundle DEVELOPMENT

- There is a need to aggregate EE savings into blocks of resources to limit IRP capacity expansion model run-time, but also to avoid an “all-or-nothing” selection scenario, given variability in EE measure costs.
- In total, 6 EE bundles were created
  - 3 residential (low/medium, high, behavior)
  - 2 commercial (low/medium, high)
  - 1 income-qualified bundle
- Used prior MPS models to estimate end-use level savings within each EE bundle, and assigned KY-specific end-use load shapes to determine savings at an hourly level
- EE bundles were also broken out into three different time vintages (2023-2025, 2026-2030, and 2031-2042) to align with subsequent planning periods

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Portfolio Technology Optimization Limits

Category	Technology	First Year Available	Block Size (MW)	Annual Limit (MW)	Cumulative Limit (MW)
Thermal	Coal with 90% CCS	2029	650	-	-
	Gas CC—single shaft (1x1)	2029	418	-	-
	Gas CC—multi shaft (2x1)	2029	1083	-	-
	Gas CC with 90% CCS	2029	377	-	-
	Gas Reciprocating ICE	2029	21	105	-
	Gas CT—aeroderivative	2029	105	210	-
	Gas CT—industrial frame	2029	240	480	720
	Hydrogen CT	2032	240	480	720
	Nuclear SMR	2033	600	600	-
Storage	Li-ion Battery (4-hr)	2026	50	200	500
	Flow Battery (20 hr)	2026	50	200	500
	Compressed Air (20 hr)	2029	50	200	500
	Pumped Thermal (20 hr)	2029	50	200	500
Renewable	Tier 1 Wind	2026	100	100	1200
	Tier 2 Wind	2026	100	300	
	Tier 1 PV with tracking	2026	50	150	1800
	Tier 2 PV with tracking	2026	50	300	
	Solar PV with storage	2026	50	300	600
	Market Capacity	2023-2025, 2028	1	500	n/a
		2026,27,30,31,33,34,36,37		235	n/a

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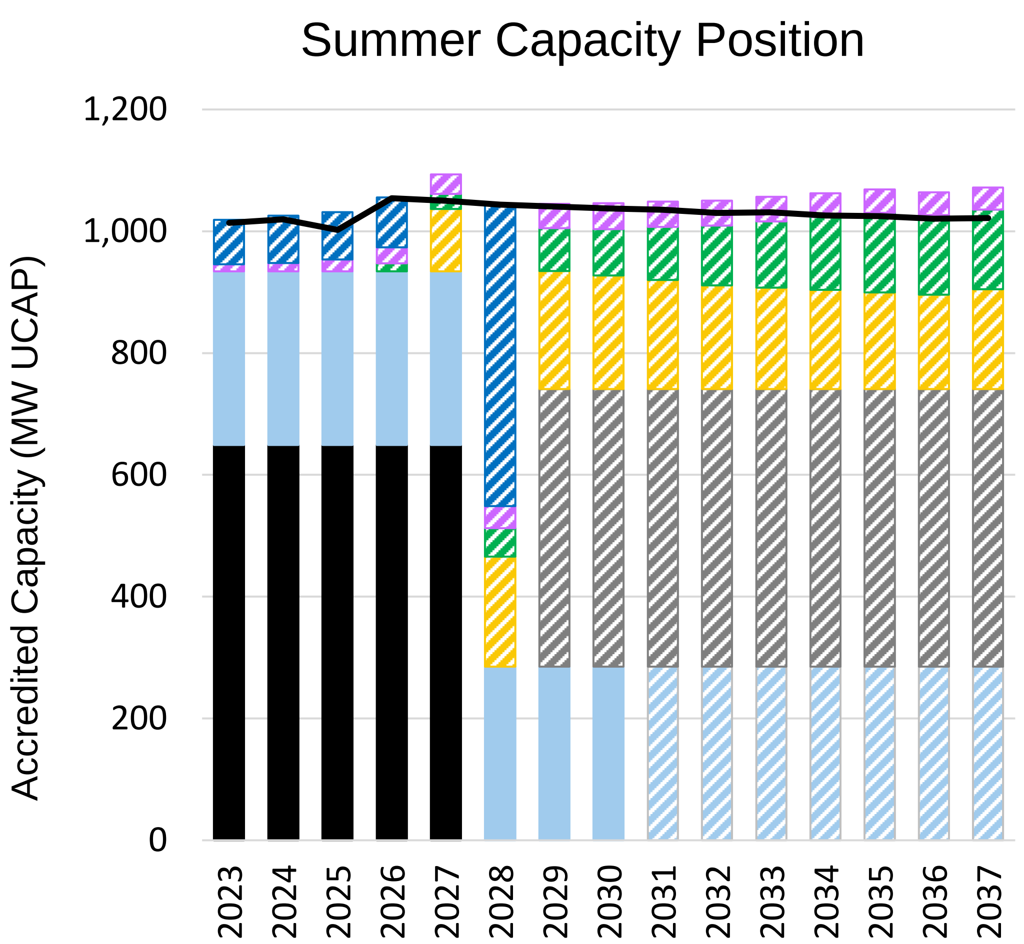
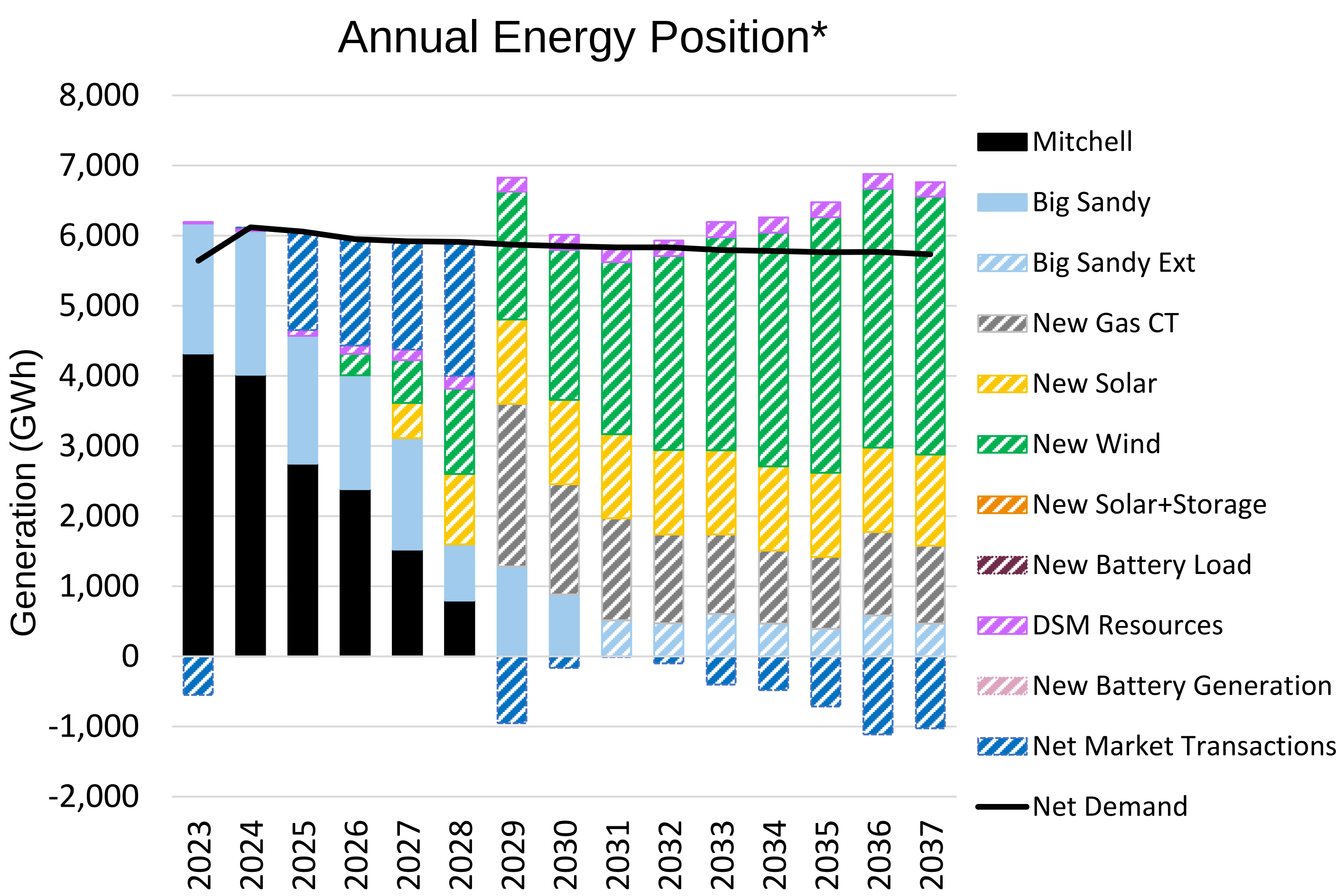
Reference Portfolio Balance





* Net market transactions are a function of economic dispatch of existing resources. The portfolio contains sufficient generating capacity to fully meet energy demand.

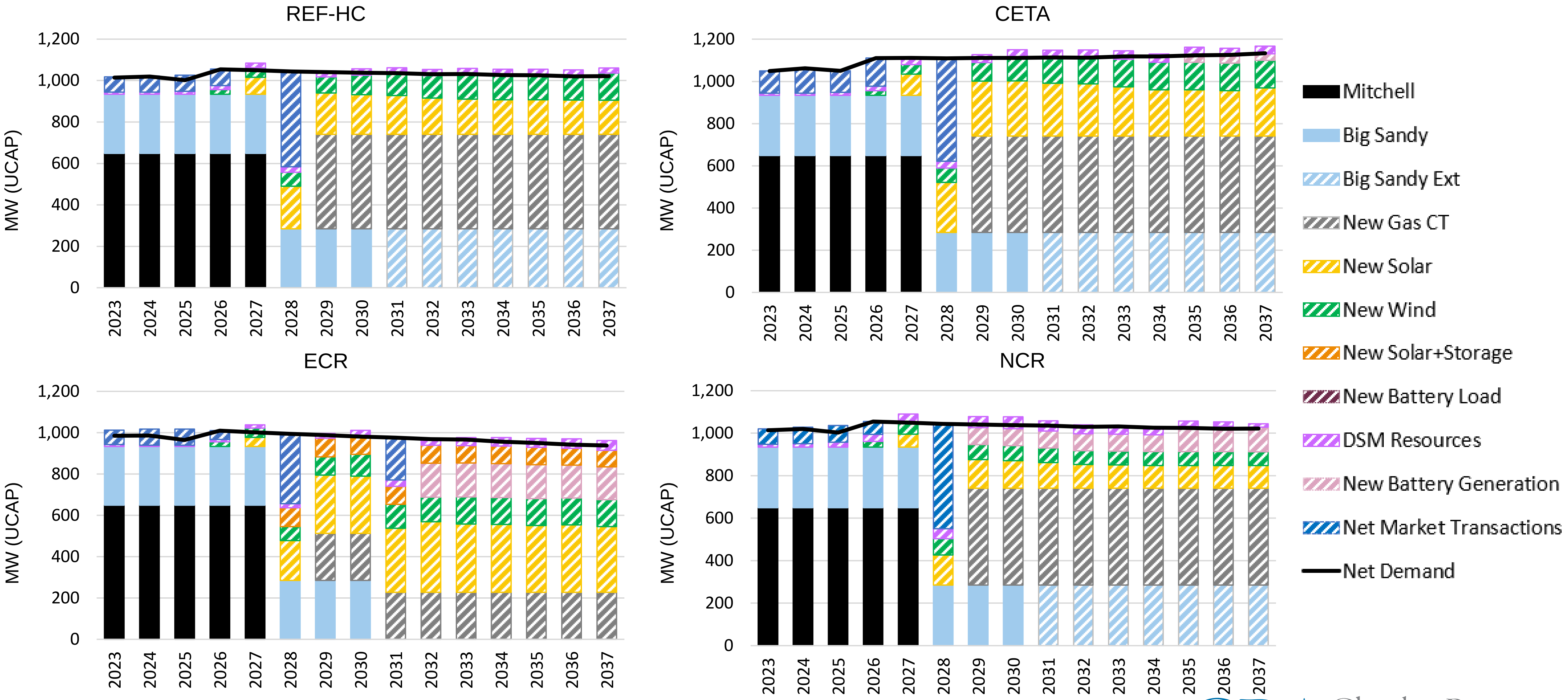
Reference Portfolio Build Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							78
2026			100				82
2027		150	100				
2028		150/100	100/100				495
2029	480	100	100/100				
2030			100				
2031			100	295			
2032			100				
2033			100				
2034			100				
2035			100				
2036							
2037		50					
Total	480	550	1200	295	0	0	

Demand-side Resource Supply by Year (MW)		
Year	DSM Programs	Total +9%
2023	12.0	13.0
2024	13.7	14.9
2025	19.5	21.3
2026	26.2	28.5
2027	31.7	34.5
2028	36.2	39.4
2029	39.7	43.2
2030	42.3	46.1
2031	41.9	45.6
2032	41.1	44.8
2033	40.2	43.8
2034	39.3	42.8
2035	38.4	41.8
2036	37.4	40.7
2037	36.3	39.5

*Capacity purchases in 2023 and 2024 have already been completed

Comparison of Capacity Balance by Portfolio



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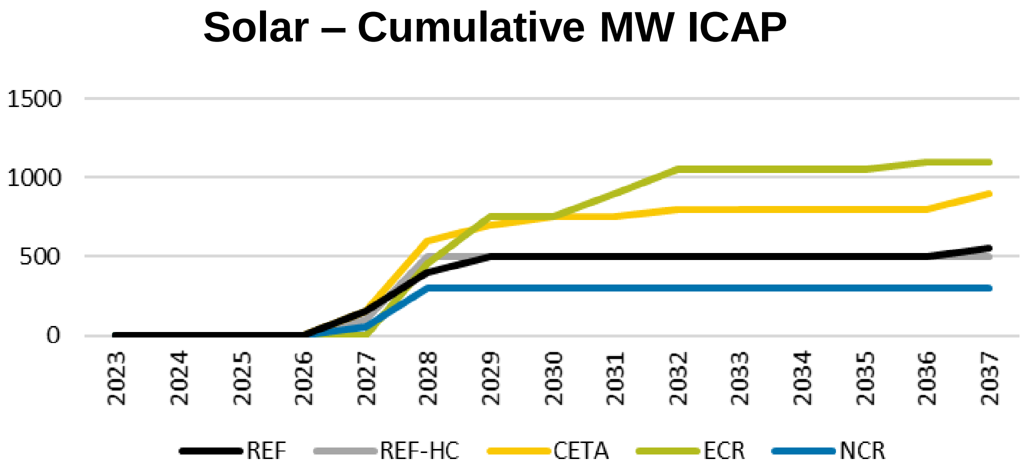
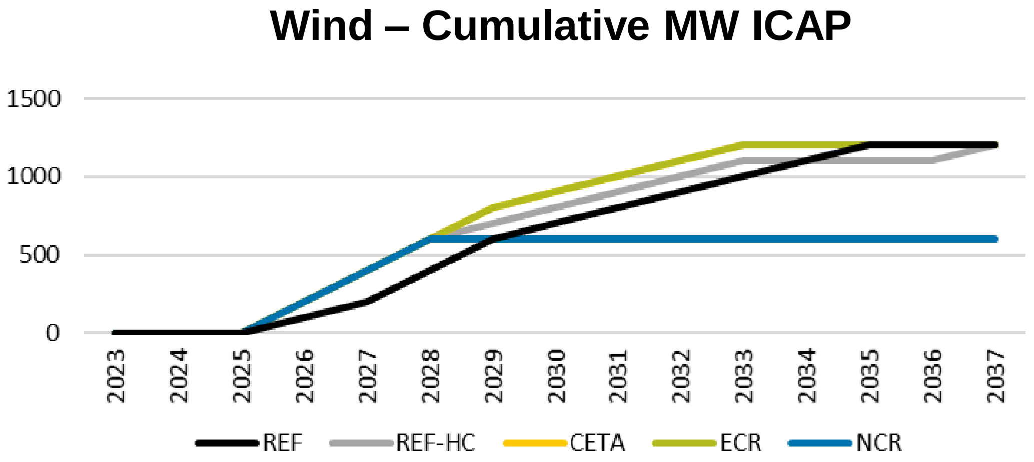
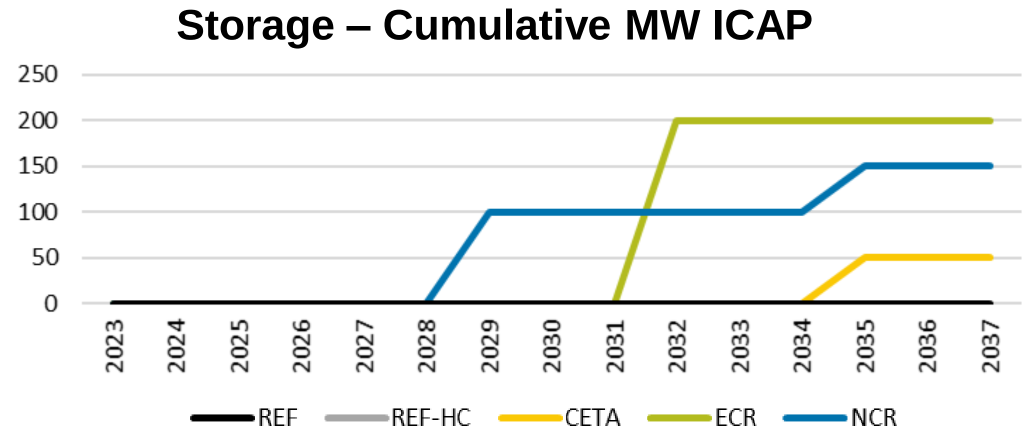
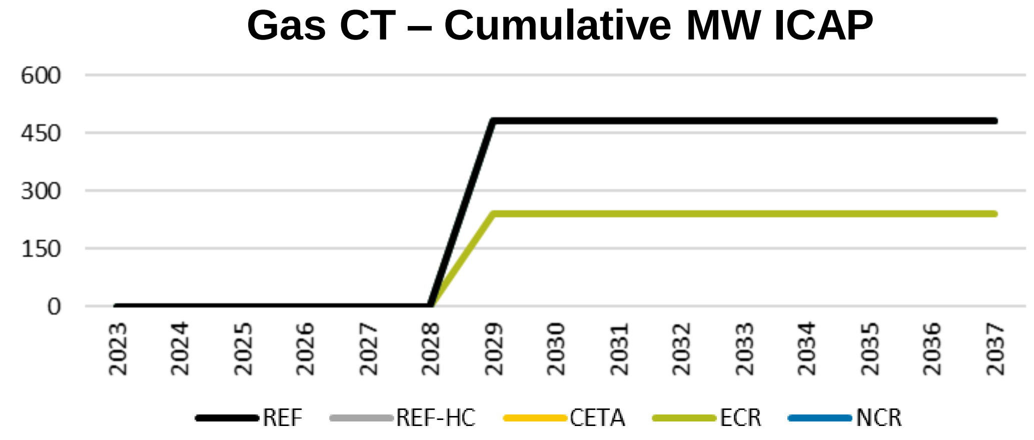
Comparison of New Resource Additions



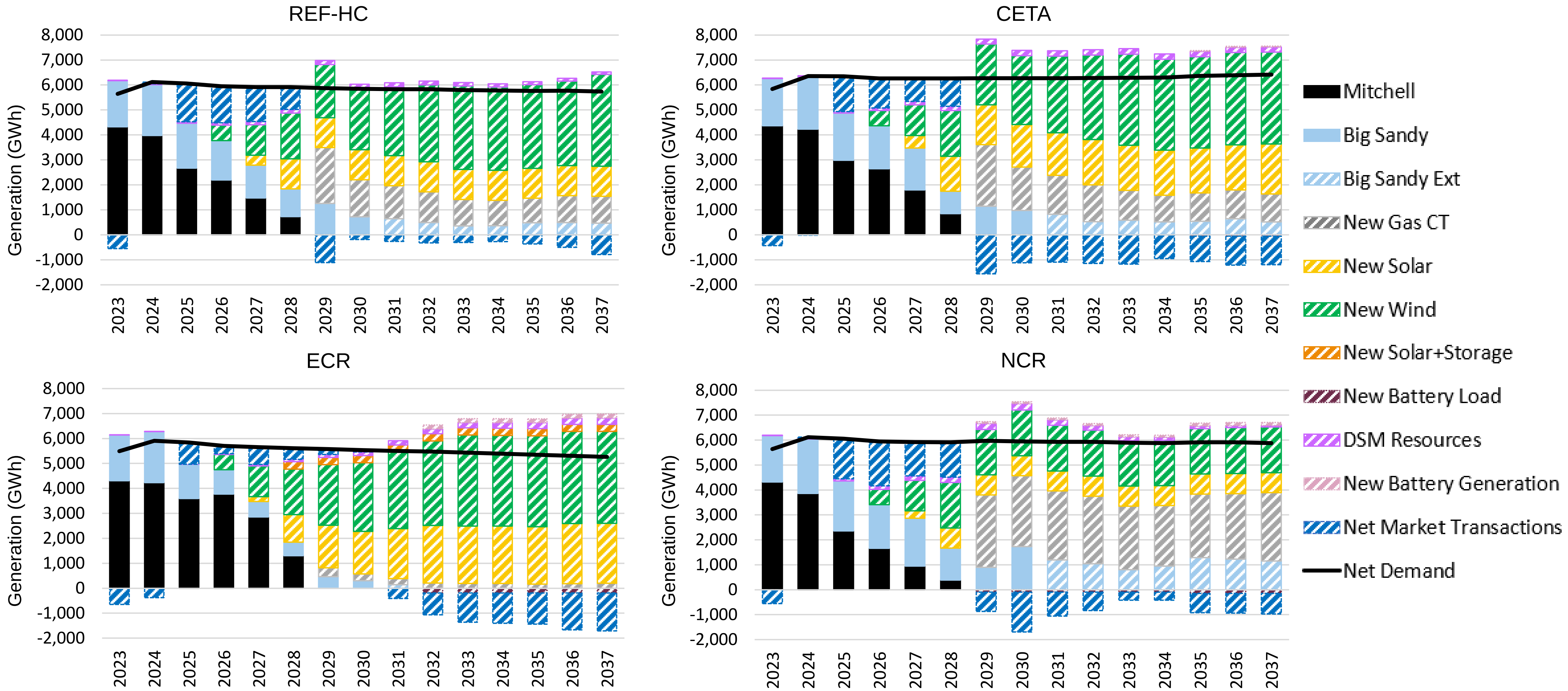






*REF and REF HC have similar solar buildouts and are superimpose. Gas CT buildout is same for all portfolios except ECR.

Comparison of Energy Balance by Portfolio



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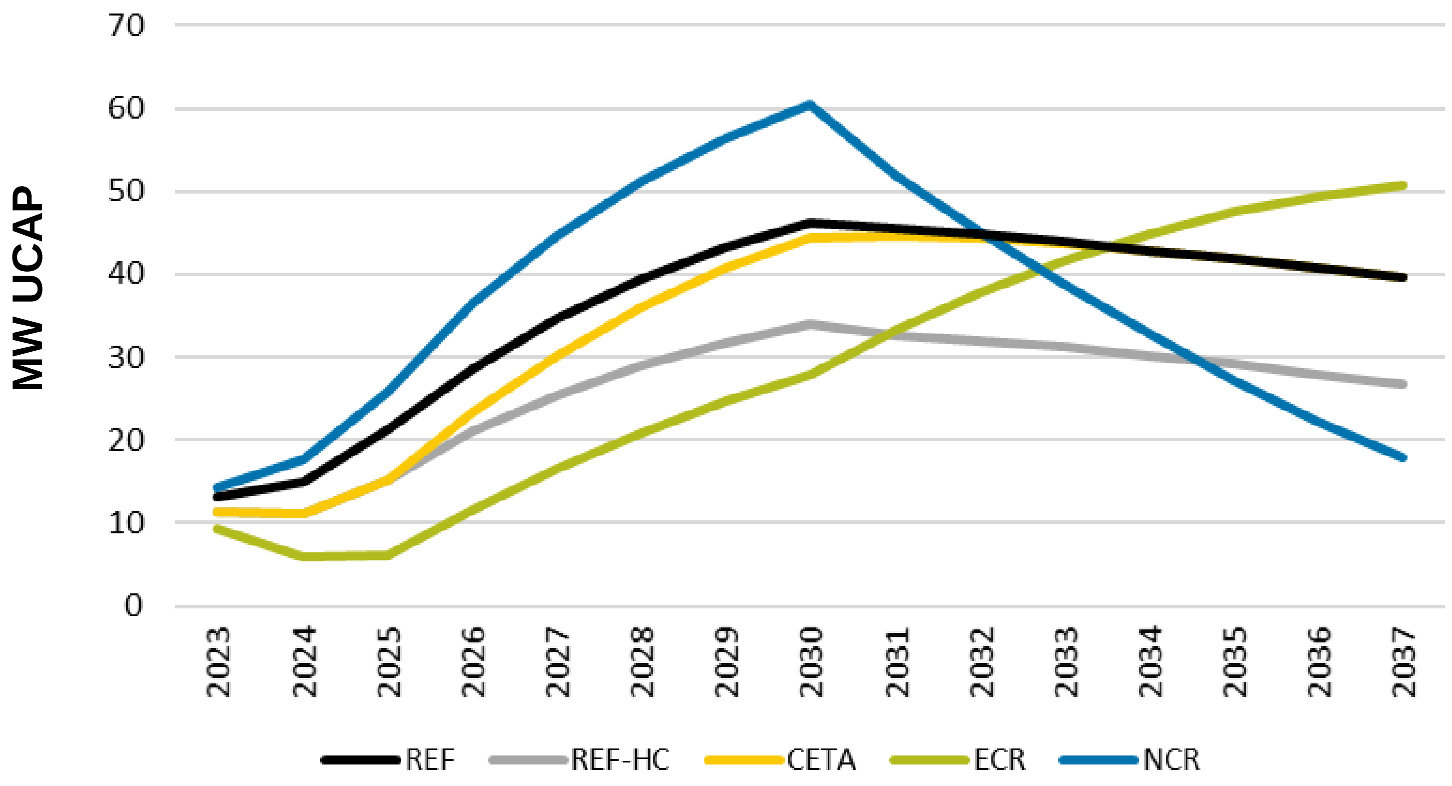
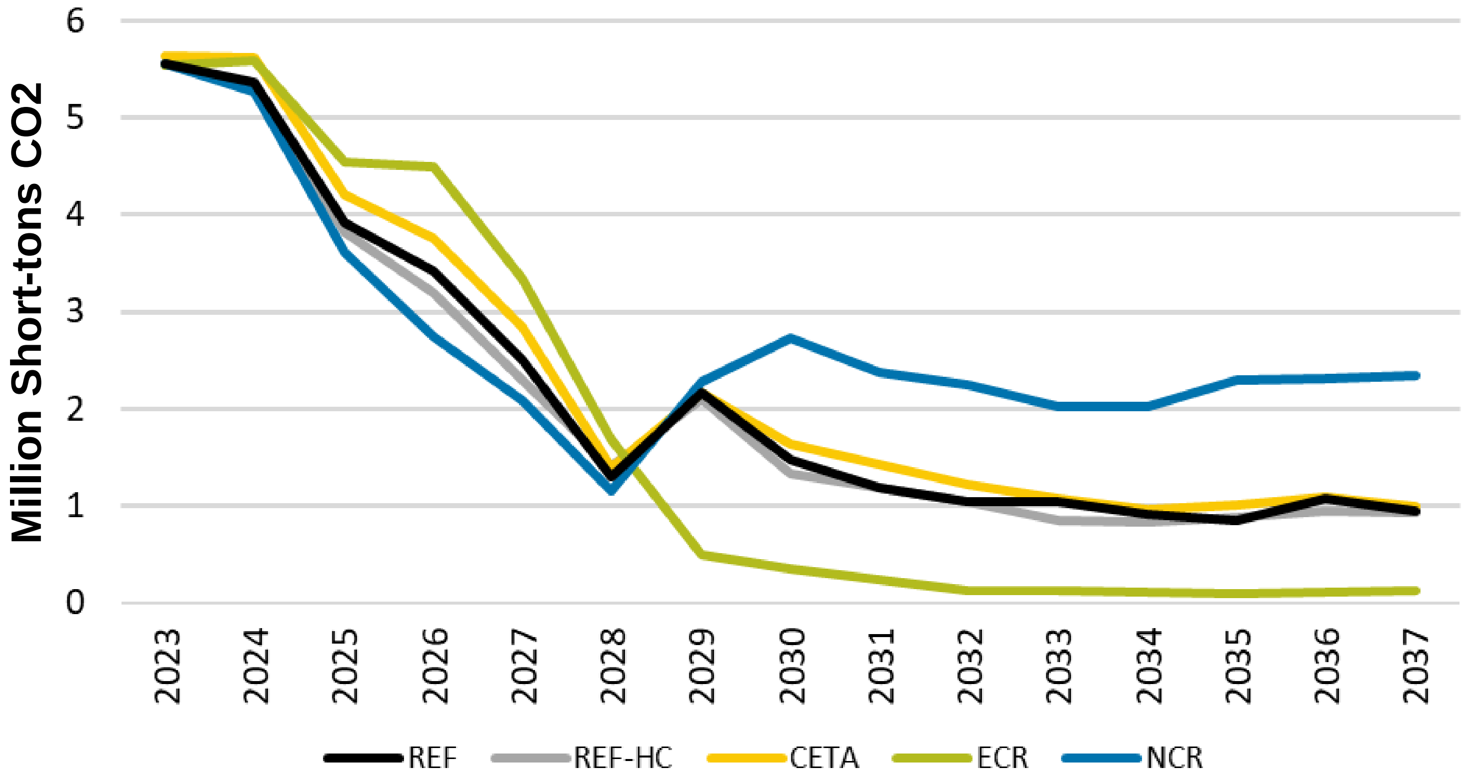
Comparison of DSM Resource



The peak contribution of energy efficiency measures tend to decline over time as technologies included in the efficiency bundles become more widely adopted and included in the load forecast. The ECR Portfolio selected more programs starting in 2031 than the other portfolios and peaks later as a result.

Comparison of CO2 Emissions by Portfolio



The decline in carbon emissions occurs most drastically in the ECR portfolio under the ECR case due to emissions being regulated through a federal carbon cap and trade program that results in a significant CO2 price and a long-term power sector net zero trajectory. Each portfolio is shown in their respective scenario.

Portfolio Key Takeaways

- **Emissions Reduction** - All portfolios feature a significant reduction in emissions intensity as existing coal units are replaced by a combination of gas and renewable resources.
- **No Gas CC** - New natural gas combined cycles are not selected as an optimal solution under any of the market scenarios, even those featuring low natural gas prices and zero CO2 price.
- **Gas CT vs Storage** - New gas combustion turbines are preferred to 4-hr Battery Storage under all market conditions, including a combination of high natural gas and high CO2 prices.
- **Wind vs Solar** - Wind is preferred to solar due mostly to relatively higher capacity factor in the region surrounding Kentucky Power.
- **No Advanced Tech** - Despite the assumed improvement in resource costs, advanced technologies including hydrogen-fired CTs, SMR nuclear, and long-duration storage technologies are not selected under any market conditions.

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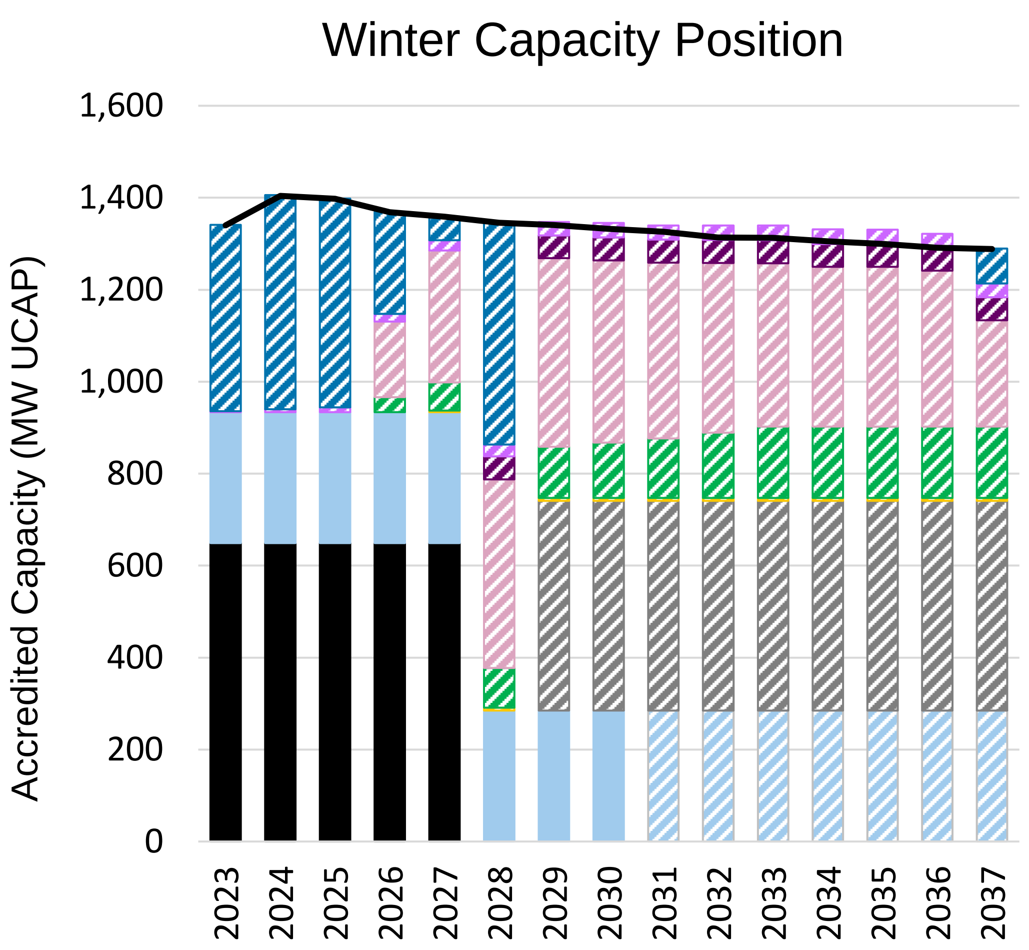
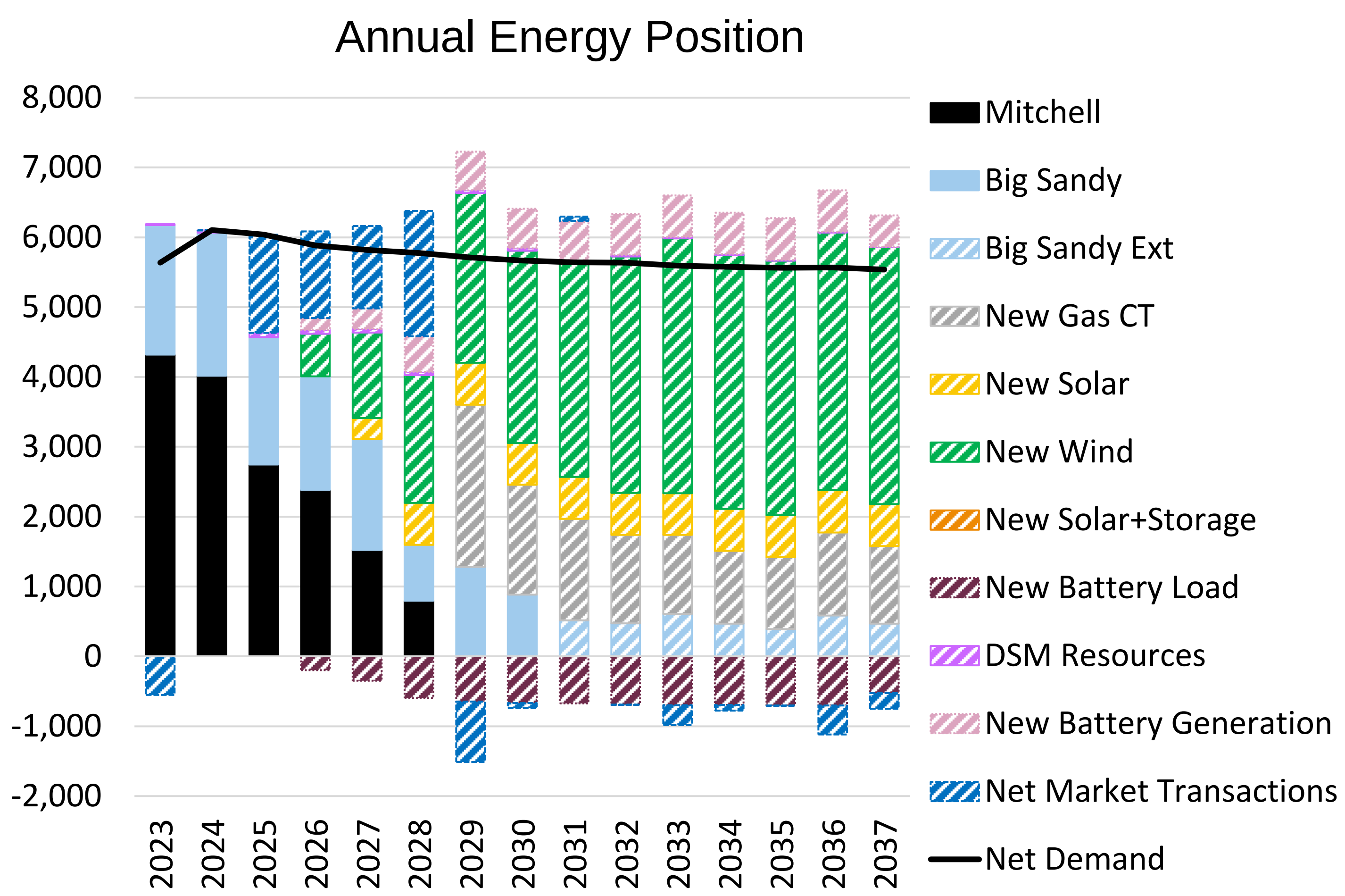
Reference Portfolio Balance - Winter Sensitivity





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Evaluation of the Preferred Plan

The resulting set of five candidate portfolios will be stress-tested to evaluate performance under adverse or unexpected conditions and the results populated in a Balanced Scorecard. This process has two steps:

Scenario Analysis
Tests Performance Under Integrated Set of Assumptions

- Each candidate portfolio is dispatched in every IRP Market Scenario to evaluate the level of customer exposure to higher costs under unexpected conditions
- This approach answers "what if…" questions and tests outcomes where major events change fundamental outlooks for key drivers after investments are made, altering portfolio performance

Stochastic Analysis
Tests Performance Under a Distribution of Inputs

- The stochastic analysis incorporates hourly volatility into energy prices, natural gas prices, and hourly renewable generation to test the impacts of extreme weather and high-cost market events
- Stochastics evaluate volatility and "tail risk" impacts
  - Market price volatility and resource output uncertainty are more complex than what can be assessed under "expected" or "weather normal" conditions
  - Commodity price exposure risk is broader than any single scenario range (i.e., February 2021 winter storm)

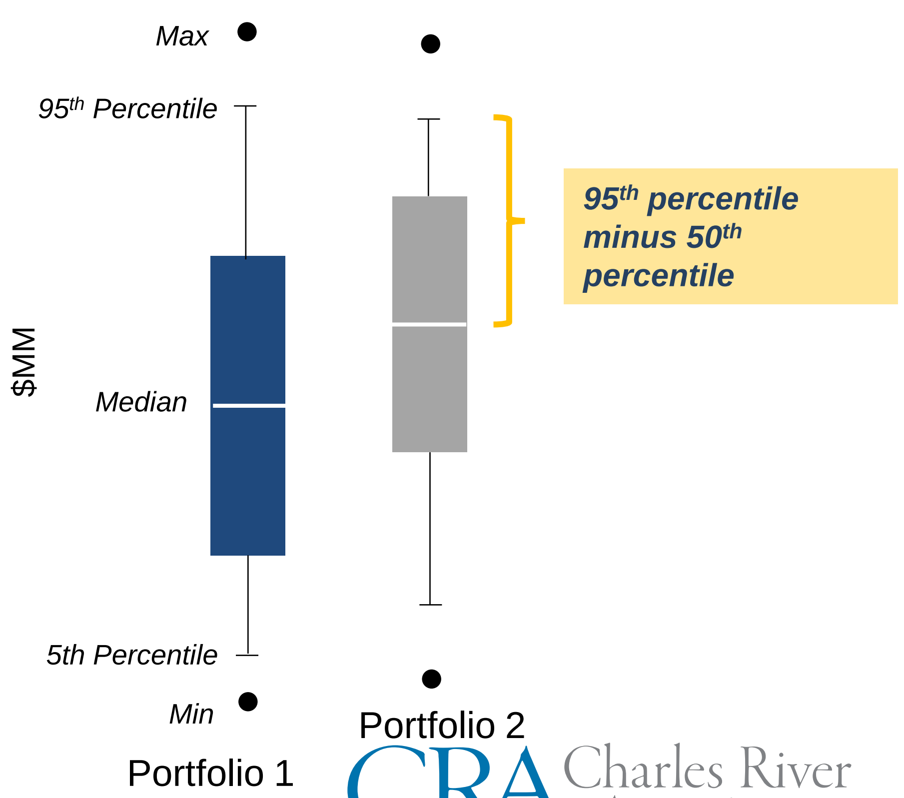
Stochastic Analysis

The stochastic analysis evaluates each candidate portfolio across 250 random combinations of market conditions to evaluate exposure to higher costs during periods of volatility.

IRP Stochastic Variables

Electricity Prices	• Hourly power prices may vary significantly during periods of extreme weather or plant outages • Evaluating random draws of power prices – in combination with other variables – allows Kentucky Power to test the robustness of candidate portfolios under volatile market conditions
Natural Gas Prices	• Daily natural gas prices can be highly variable depending on weather and broader system conditions • Natural gas fuel costs are expected to be an important component of total system costs under various candidate portfolios
Wind & Solar Output	• Evaluating variability of renewable generation through unit output uncertainty allows Kentucky Power to assess rate stability and affordability metrics as corporate sustainability targets are met

Measuring Cost Risk



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Candidate portfolios will be evaluated on an IRP Scorecard

- The Scorecard does not select the Preferred Plan by itself, rather it illustrates the trade-offs between alternative resource strategies across performance indicators and metrics defined under each objective.
- Kentucky Power will select a preferred plan that limits cost and risk and meets other IRP objectives.

The IRP Scorecard is aligned to Objectives defined by the Company and its customers

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-yr Cost CAGR, Reference Case*	***Long Term:*** *15-yr CPW, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 15-yr CPW*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside Service Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2023-2028	2023-2037	2023-2037	2037	2037	2023-2037	2027 | 2037	2037	2023-2037	2027 | 2037
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM Levelized Rate	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction

Performance Indicators on the Scorecard are measurable categories of performance that reflect the IRP Objectives

Metrics on the Scorecard are developed from the IRP modeling results and used to quantify performance and populate the IRP Scorecard

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Objective: Customer Affordability

The Customer Affordability indicators compare the cost to customers under the Reference Case Market Scenario over the short- and long-term. These metrics illustrate differences in performance under the expected case.

Performance Indicator	Metric	Description
Short-term	5-year Rate CAGR under the Reference Scenario (2023-2028)	• Kentucky Power measures and considers the expected Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2023-2028 as the metrics for the short-term performance indicator. • **A lower number is better**, indicating slower growth in customer rates.
Long-term	15-yr CPW under the Reference Scenario (2023-2037)	• Kentucky Power measures and considers the growth in Cumulative Present Worth ("CPW") over 15 years as the long-term metric. • CPW represents total long-term cost paid by Kentucky Power related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital. • Kentucky Power also evaluates the levelized rate for this indicator, which is the fixed charge needed on a per MWh basis to recover the15-yr CPW. • **A lower number is better**, indicating lower costs to supply customers with power.

Objective: Customer Affordability

	Customer Affordability	
Portfolio	***Short Term:*** *5-yr Cost CAGR, Reference Case*	***Long Term:*** *15-yr CPW, Reference Case*
Year Ref.	2023-2028	2023-2037
Units	%	$MM Levelized Rate
Reference Portfolio	7.52	3,395 $62.1
Reference – High Cost Portfolio	8.53	3,435 $62.3
CETA Portfolio	9.16	3,504 $64.0
ECR Portfolio	8.21	3,605 $65.6
NCR Portfolio	7.91	3,517 $64.1

In the **Short Term**, costs rise the least under the Reference portfolio because the resource additions in this portfolio tend to occur later in the forecast. The NCR portfolio is next best when costs are compared over the next five years. The Reference High-Cost, ECR, and CETA portfolios have the highest increases. Overall, fleet turnover drives the increase in short-term rates across portfolios as the loss of Mitchell requires sizable incremental capacity additions and capex by 2028.

In the **Long Term,** the Reference portfolio has the lowest expected cost to customers, due to a combination of lower capex resource types, tax credits, and lower operating O&M. The Reference High-Cost portfolio is next best and only slightly higher cost when viewed over 15 years, followed by CETA. The NCR portfolio experiences high market purchases as a result of lower gas dispatch under Reference market conditions. The ECR portfolio is the most expensive for customers over the longer term due the highest level of installed capacity build.

Objective: Rate Stability

The Rate Stability indicators compare the risk that cost to customers will be higher than expected, either due to a change in fundamental market conditions or due to short-duration high-impact events.

Performance Indicator	Metric	Description
Scenario Range	High Minus Low Scenario Range 15-yr CPW (2023-2037)	• Kentucky Power measures and considers the range of 15-yr CPW reported by each portfolio across all PJM market Scenarios. This metric reports the difference between the highest and lowest cost scenarios reported by the candidate portfolio on an CPW and levelized rate basis. • **A lower number is better**, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions.
Cost Risk	CPW Increase in Reference Scenario - 2037 (95th minus 50th Percentile)	• Kentucky Power measures and considers the potential for customer costs to increase beyond expected levels due to market volatility or extreme weather in 2037. • This metric compares the difference between annual portfolio costs under expected market conditions and annual portfolio costs under stochastically generated market conditions that reflect high-cost market events. • **A lower number is better**, indicating that the costs of the candidate portfolio rise less when short-term market conditions are erratic or unfavorable.
Market Exposure	2037 Purchases / Sales as % of Total Portfolio Demand in Summer and Winter	• Kentucky Power measures and considers the reliance of each candidate portfolio on market sales or purchases to balance seasonal generation with customer load. • The metric reports net purchases or sales in 2037, distinguishing between market activity in the summer (June-Aug) and winter (Dec-Feb) seasons. • **Closer to zero** indicates less reliance on the market to meet energy needs

Objective: Rate Stability

	Rate Stability		
Portfolio	***Scenario Range:*** *High Minus Low Scenario Range, 15-yr CPW*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*
Year Ref.	2023-2037	2037	2037
Units	$MM Levelized Rate	$MM	Summer | Winter
Reference Portfolio	438 $8.92	77.6	14% | 30%
Reference – High Cost Portfolio	432 $8.74	72.2	10% | 26%
CETA Portfolio	565 $11.6	87.1	31% | 39%
ECR Portfolio	886 $15.1	95.8	28% | 26%
NCR Portfolio	497 $13.3	37.9	-25% | -20%

The **Scenario Range** indicator shows that expected costs under the Reference and Reference High-Cost portfolios varied the least across the fundamental market scenarios. The NCR is next best, while the CETA and ECR portfolio show the greatest variability in customer costs across the different market conditions due in large part to high market exposure.

The **Cost Risk** shows the lowest exposure to random shocks in the NCR portfolio due to lower renewable resource deployment. The ECR portfolio shows the highest exposure in 2037.

The Reference High-Cost portfolio shows the lowest level of **Market Exposure** across the candidate portfolios, relying the least on net purchases or sales to meet customer requirements. Reference shows the next least reliance on market. The CETA and ECR portfolios exhibit the greatest sales exposure due to the increased deployment of new renewable resources in this portfolio that require significant net sales to balance with customer loads. NCR is the only portfolio with an expected average purchase exposure, as more reliance on gas generation results in potential of lower dispatch across higher gas and carbon price scenarios.

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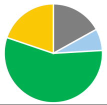
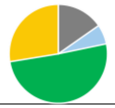
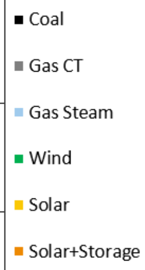
Objective: Maintaining Reliability

The Maintaining Reliability indicators compare the amount of excess reserves, the amount of dispatchable capacity in the fleet, and the technology diversity of the Kentucky Power generating mix across candidate plans.

Performance Indicator	Metric	Description
Planning Reserves	Avg. Seasonal Reserve Margin % 2023-2037	• Kentucky Power measures and considers the amount of average amount of firm capacity in each candidate portfolio over the next 15 years on a seasonal basis. • This metric is a composite calculated by averaging the winter and summer capacity position of each portfolio across all five market scenarios for years 2023-2037. • **A higher number is better**, indicating more reserves are available to meet PJM requirements.
Operational Flexibility	Nameplate MW of dispatchable units in 2027 and 2037	• Kentucky Power measures and considers the total amount of dispatchable units added to the portfolio by years 2027 and 2037 to compare candidate resource plans. • The metric for this indicator is the total Nameplate MW of fast-ramping technologies included in the candidate resource plan. • **A higher number is better,** indicating greater ability to ramp generation up or down to react to market conditions and follow load.
Resource Diversity	Generation by technology type, % of total portfolio in 2037	• Kentucky Power measures and considers the diversity of new technologies added to its portfolio when comparing candidate portfolios. • This metric is a pie-chart showing total generation by each technology type in year 2037. • **A less concentrated portfolio is better**, overreliance on a single technology exposes customers to performance risk when conditions for that technology are unfavorable.

Objective: Maintaining Reliability

	Maintaining Reliability		
Portfolio	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*
Year Ref.	2023-2037	2027 | 2037	2037
Units	Summer | Winter	MW	%
Reference Portfolio	11.3% | -22.7%	1111 | 775	
Reference – High Cost Portfolio	10.6% | -23.1%	1111 | 775	
CETA Portfolio	20.2% | -19.9%	1111 | 825	
ECR Portfolio	3.4% | -37.4%	1111 | 490	
NCR Portfolio	10.2% | -20.8%	1111 | 925	



The CETA portfolio has the greatest amount of **Planning Reserves** due the more aggressive resource build-out needed to meet faster load growth. The Reference, Reference High-Cost, and NCR portfolios are next best and adequately meet summer requirement across the range of scenarios. The ECR portfolio scores worst by this metric and may expose Kentucky Power's customers to capacity shortfalls in summer. Kentucky Power load is winter peaking, reflected in the shortfall* in the winter reserve across all portfolios.

The NCR plan scores best on the **Operational Flexibility** metric, owing to the highest level of storage, in addition to two CT units. The Reference, Reference High-Cost, and NCR portfolios are next best, while the ECR portfolio scores worst on this indicator.

The NCR portfolio scores highest on the **Resource Diversity** metric, with approximately two-thirds of energy provided by new solar and wind units and the remainder from gas. The Reference, Reference High-Cost, and CETA portfolios are the next most diverse. The ECR portfolio is the least diverse, with wind and solar dominating total portfolio generation in 2037.

*PJM does not have a winter requirement at this time; however, the winter position was investigated to understand implications of a hypothetical requirement (see portfolio results section).

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Objective: Local Impacts & Sustainability

Kentucky Power also considers Local Impacts and a Sustainability indicator to compare portfolio performance towards meeting corporate sustainability targets.

Performance Indicator	Metric	Description
Local Impacts	Nameplate MW & Total CAPEX Installed Inside Kentucky Power Territory by 2037	• Kentucky Power measures and considers the amount of new capacity that can be located inside customer communities when evaluating candidate portfolios. • This metric compares the nameplate MW installed and the total capital investment expected inside Kentucky Power's service territory under each plan from 2023-2037 (0% wind, 75% solar capacity contribution). • **A higher number is better**, indicating more opportunities for customer-sited resources and additional investment in local communities.
CO_2 Emissions	2027 & 2037 % Reduction from 2005 Baseline - Reference Case	• Kentucky Power measures and considers the total amount of expected CO2 emissions of each candidate portfolio on the Scorecard. • This metric compares the forecast emissions of candidate portfolios in 2027 and 2037 under Reference Case market conditions with Kentucky Power's actual historical emissions from the year 2000. • **A higher number is better**, indicating greater levels of emissions reductions have been achieved and customers are less exposed to potential future CO_2 costs.

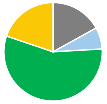
Objective: Local Impacts and Sustainability

	Local Impacts & Sustainability	
Portfolio	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside Service Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2023-2037	2027 | 2037
Units	MW | $MM	% Reduction
Reference Portfolio	893 | 1,146	74% | 90%
Reference – High Cost Portfolio	855 | 1,134	74% | 90%
CETA Portfolio	1,205 | 1,511	74% | 90%
ECR Portfolio	1,415 | 1,942	74% | 96%
NCR Portfolio	855 | 1,067	74% | 90%

The ECR portfolio scores best by the **Local Impacts** metric on both a MW basis and a dollar basis because of the highest reliance on new renewable and storage resources that tend to be more capital intense than gas-fired units. The CETA portfolio is next best by this metric on the basis of additional capacity needed to meet higher load. The Reference portfolio follows with almost 900 MW installed in the territory and a total expected investment of approximately $1.1 billion over the 15 years, which is similarly reflected in Reference High-Cost. NCR portfolio scores lowest by this measure.

All of the resource plans considered in the 2022 IRP keep Kentucky Power on a pathway to significant **CO_2 Emissions** reduction through the latter part of this decade. This result is consistent over the long term as well, with the ECR portfolio showing the highest level of emissions reduction across the candidate resource plans.

Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-yr Cost CAGR, Reference Case*	***Long Term:*** *15-yr CPW, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 15-yr CPW*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside Service Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2023-2028	2023-2037	2023-2037	2037	2037	2023-2037	2027 | 2037	2037	2023-2037	2027 | 2037
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction
Reference Portfolio	7.52	3,395 $62.1	438 $8.92	77.6	14% | 30%	11.3% | -22.7%	1111 | 775		893 | 1,146	74% | 90%
Reference – High Cost Portfolio	8.53	3,435 $62.3	432 $8.74	72.2	10% | 26%	10.6% | -23.1%	1111 | 775		855 | 1,134	74% | 90%
CETA Portfolio	9.16	3,504 $64.0	565 $11.6	87.1	31% | 39%	20.2% | -19.9%	1111 | 825		1,205 | 1,511	74% | 90%
ECR Portfolio	8.21	3,605 $65.6	886 $15.1	95.8	28% | 26%	3.4% | -37.4%	1111 | 490		1,415 | 1,942	74% | 96%
NCR Portfolio	7.91	3,517 $64.1	497 $13.3	37.9	-25% | -20%	10.2% | -20.8%	1111 | 925		855 | 1,067	74% | 90%

■ Coal
■ Gas CT
■ Gas Steam
■ Wind
■ Solar
■ Solar+Storage

*Levelized Rates and CPW metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers.

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Draft Preferred Plan

- Kentucky Power has not yet selected a Preferred Plan for the 2022 IRP.
- Following this Stakeholder Conference, Kentucky Power will consider additional Stakeholder Feedback as it proceeds to identify a Preferred Plan.

Questions?

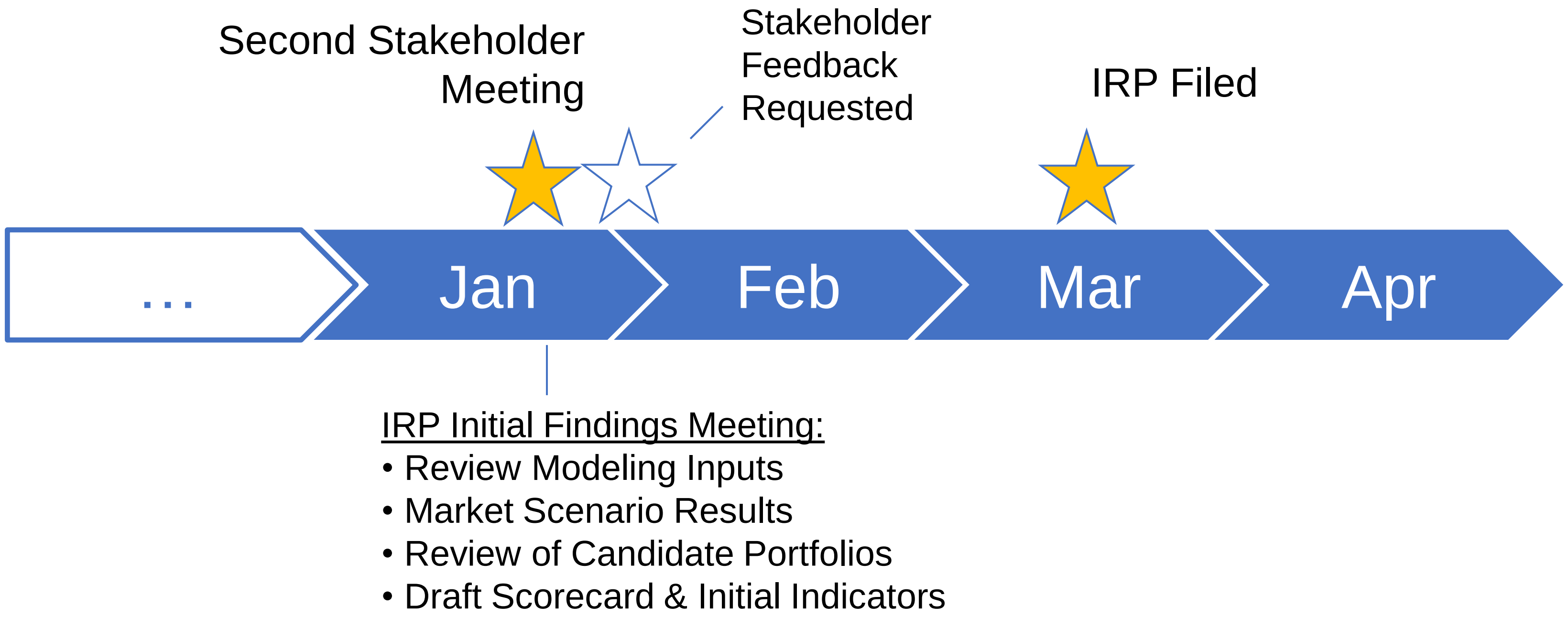
Agenda

- Welcome and Introductions
- Overview of the 2022 IRP Process
- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
- Market Scenario Results
- Portfolio Development & Results
- Portfolio Risk Analysis
- Scorecard Development
- Discussion & Closing Remarks

Stakeholder feedback is encouraged throughout the presentation.

Thank You For Participating!

- Kentucky Power requests that stakeholders provide written feedback by February 1 regarding:
  - The IRP Process and Objectives
  - The IRP Inputs and Market Scenarios
  - Development and Evaluation of Candidate Resource Plans
- Please contact kentucky_regulatory_services@aep.com with any additional questions.



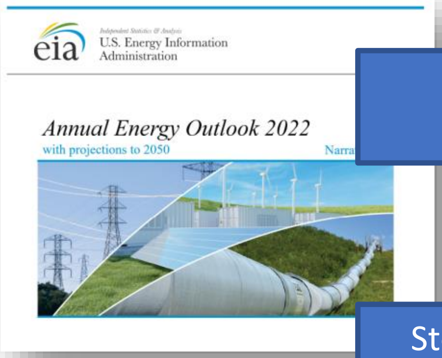
Appendix

Approach to Developing New Unit Assumptions

Inputs for these resources have traditionally been developed based on authoritative third-party sources.

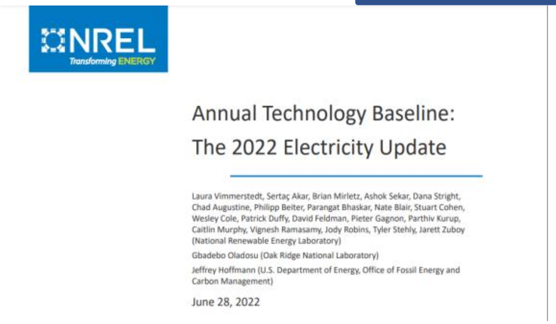
Intermediate & Peaking Options

Renewable Options



Step 1: Sourcing baseline technology costs and performance assumptions from EIA Annual Energy Outlook*

Step 2: Applying changes to technology cost and performance over time based on the Moderate Case projection by the National Renewable Energy Laboratory's Annual Technology Baseline*


NREL
Transforming ENERGY

Annual Technology Baseline:
The 2022 Electricity Update

Laura Vimmerstedt, Sertaç Akar, Brian Mirletz, Ashok Sekar, Dana Stright, Chad Augustine, Philipp Beiter, Parangat Bhaskar, Nate Blair, Stuart Cohen, Wesley Cole, Patrick Duffy, David Feldman, Pieter Gagnon, Parthiv Kurup, Caitlin Murphy, Vignesh Ramasamy, Jody Robins, Tyler Stehly, Jarett Zuboy (National Renewable Energy Laboratory)

Gbadebo Oladosu (Oak Ridge National Laboratory)

Jeffrey Hoffmann (U.S. Department of Energy, Office of Fossil Energy and Carbon Management)

June 28, 2022

Step 3: Applying investment tax credit for wind project entering service before the end of 2025, and 30% production tax credit for solar project entering service before the end of 2023, 26% before the end of 2025 and 10% thereafter

Advanced Generation & Storage

Step 1: Collate projections of technology costs and performance from various third-party sources

Step 2: Analyze projections, identify outliers and form central estimates of technology costs and performance over time

New supply-side resources

CRA evaluated broad range of resource types as part of the 2022 IRP that includes thermal, renewable, and emerging technologies that may be needed to support future electric-sector decarbonization.

Intermediate & Peaking Options

- H-Class 430 MW single-shaft natural gas combined cycle (NGCC)
- H-Class 1,100 MW multi-shaft NGCC
- F-Class 240 MW natural gas combustion turbine (NGCT)
- 650 MW ultra-supercritical coal (USC) unit with 90% carbon capture
- 430 MW H-class single shaft NGCC with 90% carbon capture
- 100 MW aeroderivative unit
- 20 MW reciprocating engine
- 4-hour duration lithium-ion battery

Renewable Options

- Utility-scale onshore Wind
- Utility-scale solar photovoltaic
- Utility-scale paired solar + storage

Advanced Generation & Storage

- Small modular nuclear reactors
- 90% carbon capture retrofits to existing coal or NGCC units
- Hydrogen electrolyzer + hydrogen gas combustion turbine
- Hydrogen gas combustion turbine
- 20-hour duration pumped thermal energy storage
- 20-hour vanadium flow battery storage
- 20-hour compressed air energy storage

Baseline Assumptions

CRA developed baseline technology cost and performance assumptions before applying learning rates that improve costs over time.

Technology	Life (years)	Fuel	Overnight CAPEX^^ ($2021/kW)	VOM ($2021/MWh)	FOM ($2021/kW-yr)	Heat Rate (Btu/kWh)	LCOE^^ (Nominal $/MWh)	Capacity Factor (%)
NGCC H-Class Single-Shaft 430 MW	30	Natural Gas	1,194	2.67	14.76	6,431	70	72%
NGCC H-Class Multi-Shaft 1,100 MW	30	Natural Gas	1,037	1.96	12.77	6,370	64	75%
NGCT F-Class 240 MW	30	Natural Gas	753	0.62^	7.33	9,905	100	31%
Coal USC 650 MW with 90% Carbon Capture	40	Coal	6,601	11.49*	62.34	12,507	265	52%
NGCC H-Class 430 MW with 90% Carbon Capture	40	Natural Gas	3,000	6.11*	28.89	7,124	193	34%
100 MW Aeroderivative	30	Natural Gas	1,242	4.92	17.06	9,124	141	27%
20 MW Reciprocating Engines	20	Natural Gas	1,980	5.96	36.81	8,295	149	43%
4-Hour Duration Lithium-Ion Battery	10	N/A	1,432	-	25.57	-	N/A	9%
Utility-scale Onshore Wind Tier 1	30	N/A	1,411	-	27.57	-	46	35%
Utility-scale Onshore Wind Tier 2	30	N/A	1,552	-	27.57	-	52	35%
Utility-scale Solar Photovoltaic Tier 1	30	N/A	1,320	-	14.81	-	69	23%
Utility-scale Solar Photovoltaic Tier 2	30	N/A	1,452	-	14.81	-	77	23%
Utility-scale Solar + Storage (3:1)	30	N/A	1,721	-	33.67	-	114	16%
Small Modular Reactor	40	Uranium	6,875	3.14	99.46	10,443	159	87%
Hydrogen Electrolyzer + Hydrogen Gas CT	30	Electricity	3,295	1.12** ^	54.16	-	N/A***	1%
Hydrogen Gas Combustion Turbine	30	Hydrogen	1,576	0.62** ^	7.33	9,655	N/A***	1%
20-Hour Duration Pumped Thermal Energy Storage	20	N/A	3,336	-	51.72	-	N/A	8%
20-Hour Duration Vanadium Flow Battery Storage	10	N/A	3,844	-	11.45	-	N/A	2%
20-Hour Duration Compressed Air Energy Storage	25	N/A	1,788	-	17.37	-	N/A	6%

*The Section 45Q legislation provides a tax credit of $94/short-ton CO_2 sequestered, implemented as a negative VOM adder
**The IRA tax credit provides a tax credit of $3/kg of hydrogen, implemented as a levelized $/MMBtu adjustment to fuel pricing
***Low dispatch levels make LCOE an unsuitable metric for Hydrogen
^Start cost of $79/MW additional to VOM
^^First year

Tax Credit Assumptions

	Previous Policy		Inflation Reduction Act								
Operational Year	Wind PTC	Solar ITC	Wind PTC	Wind ITC	Solar PTC	Solar ITC	Clean Energy PTC	Clean Energy ITC	Storage ITC	CCS	Hydrogen
Credit 2021$	$25/MWh		$25/MWh		$25/MWh		$25/MWh				$/kg
2022	60%	26%	100%	30%	100%	30%				$85	$3
2023	60%	26%	100%	30%	100%	30%				$85	$3
2024	60%	26%	100%	30%	100%	30%				$85	$3
2025	60%	26%					100%	30%	30%	$85	$3
2026	0%	10%					100%	30%	30%	$85	$3
2027	0%	10%					100%	30%	30%	$85	$3
2028	0%	10%					100%	30%	30%	$85	$3
2029	0%	10%					100%	30%	30%	$85	$3
2030	0%	10%					100%	30%	30%	$85	$3
2031	0%	10%					100%	30%	30%	$85	$3
2032	0%	10%					100%	30%	30%	$85	$3
2033	0%	10%					75%	22.5%	22.5%		
2034	0%	10%					50%	15%	15%		
2035+	0%	10%					0%	0%	0%		
Notes	(1)	(2)	(1), (3), (4), (7)	(2), (3), (4), (7)	(1), (3), (4), (7)	(2), (3), (4), (7)	(1), (3), (4), (7)	(2), (3), (4), (7)	(3), (4), (7)	(3),(5), (7)	(7), (8)

(1) 10-year production tax credit (PTC) available, assuming plant is operational by end of year and properly safe-harbored. The 2021 PTC value was $25/MWh. This value is subject to inflation escalation each year by the IRS. Solar PTC revived in IRA (solar is eligible for either PTC or ITC).

(2) Investment tax credit (ITC) available, assuming plant is operational by end of year and properly safe-harbored. Wind ITC revived (Wind eligible for PTC or ITC).

(3) Direct-pay option assuming prevailing wage and apprenticeship requirements are met.

(4) Technology neutral PTC or ITC from 2025 onwards until the "applicable year", which is the latter of 2032 or the calendar year when annual greenhouse gas emissions from production of electricity in US are equal to or less than 25% of annual greenhouse gas emissions from production of electricity in 2022. Phase-out percentage is applied to value of the tax credit at 100% in the applicable year, 75% in the second calendar year following the applicable year, 50% in the third calendar year, and 0% in the subsequent year.

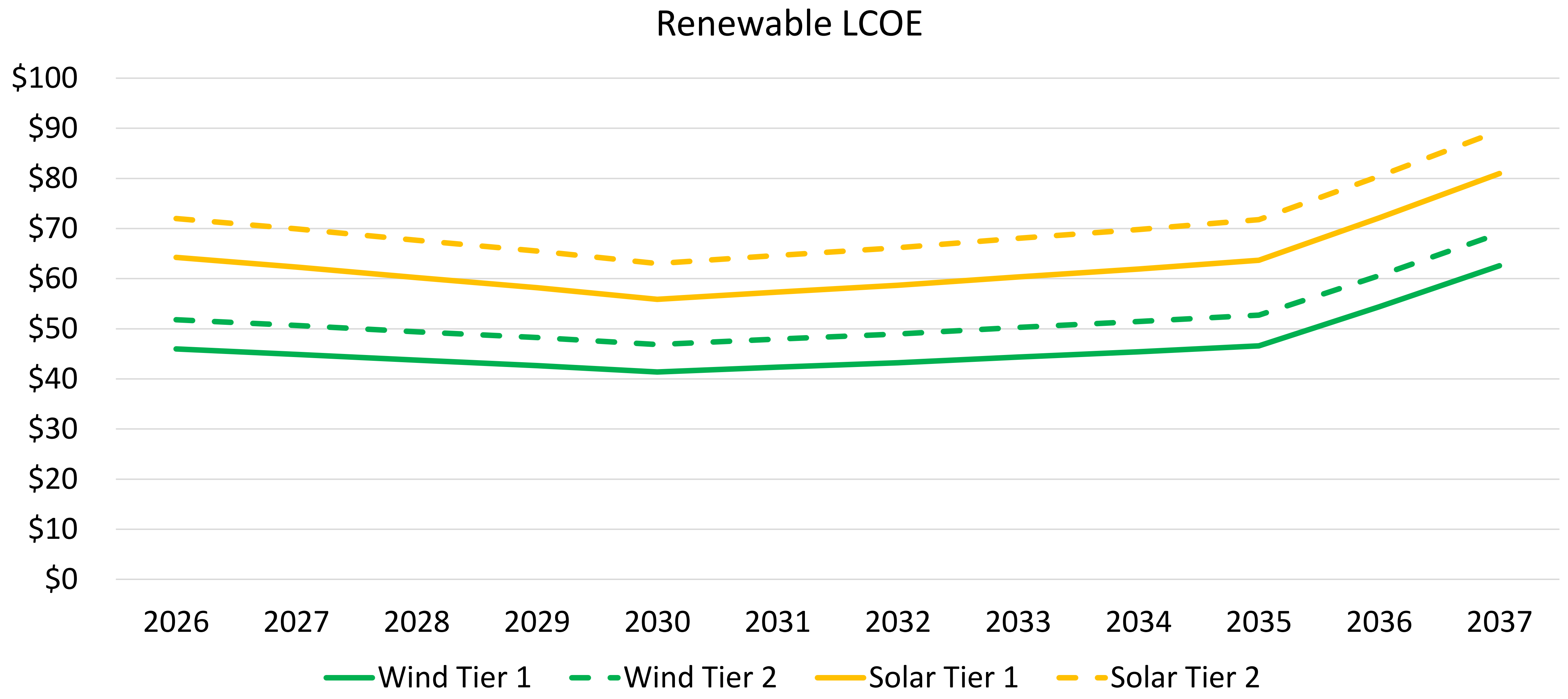
(5) $85/ton CO2 applicable to geologic storage; $60/ton CO2 applicable to EOR; $180/ton CO2 applicable to DAC. 10-year credit.

(6) Additional 10% bonus credit available if facility meets domestic manufacturing requirements. Additional 10% bonus credit if in energy community.

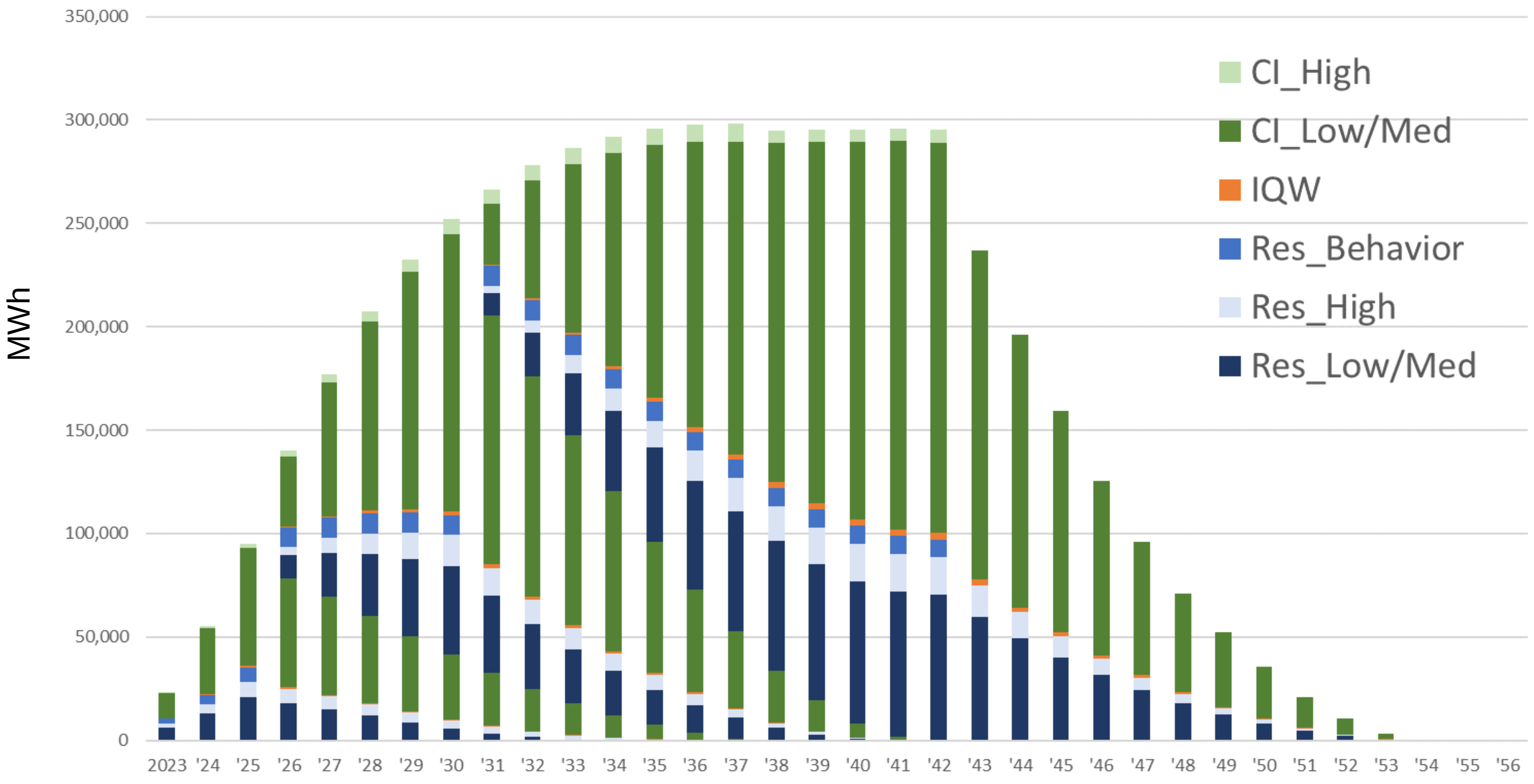
(7) Assumes prevailing wage and apprenticeship requirements are met.

(8) Assuming carbon intensities criteria are met.

Renewable LCOE – Reference



EE Bundles - Potential



* Savings shown are lifetime savings, and extend beyond 2042 IRP horizon

Levelized $/Lifetime MWh Saved

V1	V2	V3
$148	$147	$147
$33	$35	$33
$278	$300	$351
$57	$63	$79
$218	$225	$254
$57	$52	$48

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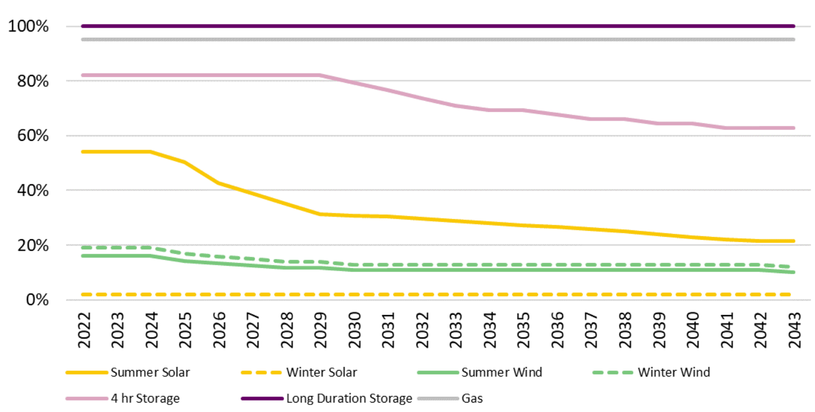
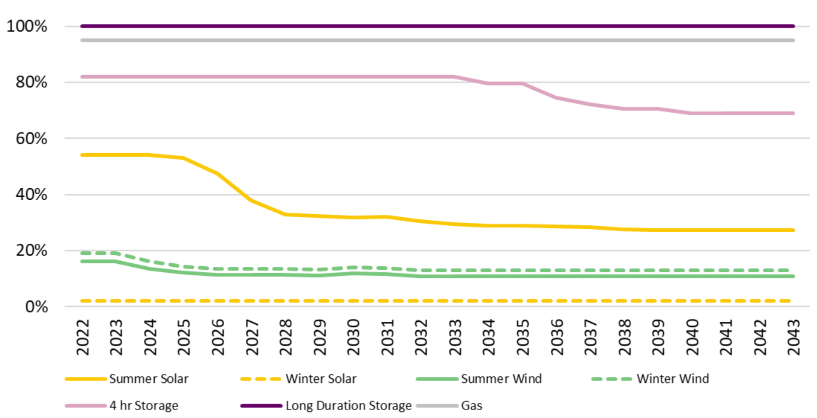
Appendix – ELCC Assumptions

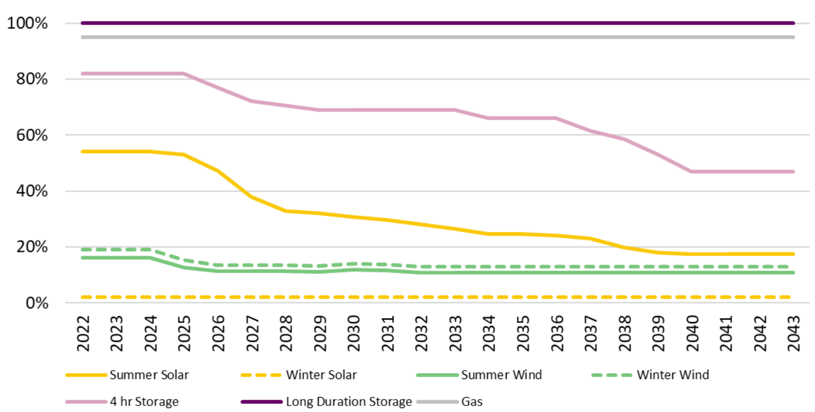
REF



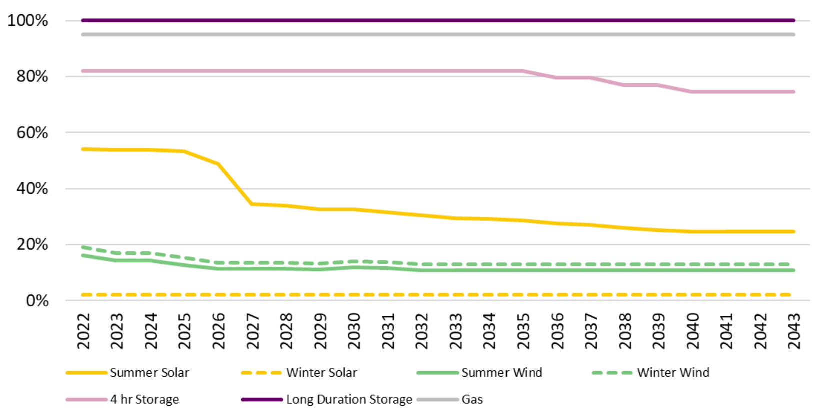
REF-HC



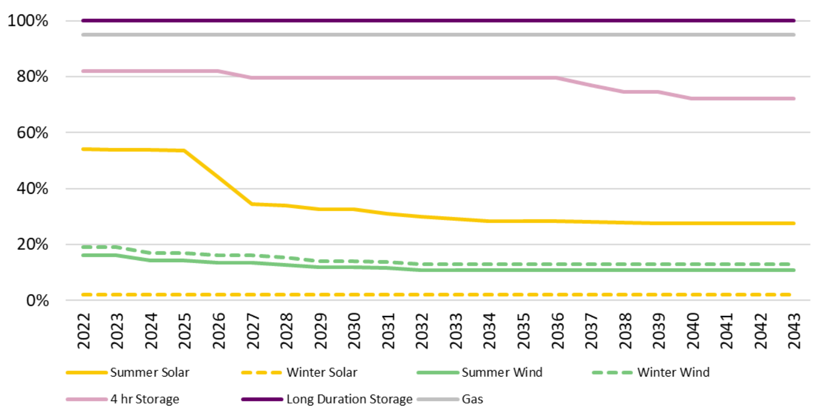
CETA



ECR



NCR



KP Optimization Results Summery - Cumulative Additions

ICAP MW	Gas CT	Thermal - Other	Solar	Wind	Solar+ Storage	Li-Ion 4hr	Flow 20hr	Storage - Other	Big Sandy Ext	DSM (max)	Capacity Purchase (max)
REF	480		550	1200					295	46	495
REF-HC	480		500	1200					295	34	461
CETA	480		900	1200		50			295	45	488
ECR	240		1100	1200	200	200				51	339
NCR	480		300	600		150			295	60	494

KP Optimization Results Summary - Comparison to Reference

ICAP MW	Gas CT	Thermal - Other	Solar	Wind	Solar+ Storage	Li-Ion 4hr	Flow 20hr	Storage - Other	Big Sandy Ext	DSM (max)	Capacity Purchase (max)
REF	480		550	1200	-	-			295	46	495
REF-HC	-		-50	-	-	-			-	-12	-34
CETA	-		+350	-	-	+50			-	-1	-7
ECR	-240		+550	-	+200	+200			-295	+5	-156
NCR	-		-250	-600	-	+150			-	+14	-1

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Reference Portfolio Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							78
2026			100				82
2027		150	100				
2028		150/100	100/100				495
2029	480	100	100/100				
2030			100				
2031			100	295			
2032			100				
2033			100				
2034			100				
2035			100				
2036							
2037		50					
Total	480	550	1200	295	0	0	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	12.0	13.0
2024	13.7	14.9
2025	19.5	21.3
2026	26.2	28.5
2027	31.7	34.5
2028	36.2	39.4
2029	39.7	43.2
2030	42.3	46.1
2031	41.9	45.6
2032	41.1	44.8
2033	40.2	43.8
2034	39.3	42.8
2035	38.4	41.8
2036	37.4	40.7
2037	36.3	39.5

*Capacity purchases in 2023 and 2024 have already been completed

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Reference High Cost Portfolio Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							78
2026			100/100				79
2027		100	100/100				
2028		150/250	100/100				461
2029	480		100				
2030			100				
2031			100	295			
2032			100				
2033			100				
2034							
2035							
2036							
2037			100				
Total	480	500	1200	295	0	0	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	10.3	11.3
2024	10.2	11.1
2025	13.9	15.2
2026	19.4	21.1
2027	23.2	25.3
2028	26.5	28.9
2029	29.2	31.8
2030	31.2	34.0
2031	29.9	32.5
2032	29.4	32.0
2033	28.6	31.2
2034	27.7	30.2
2035	26.7	29.1
2036	25.7	28.0
2037	24.6	26.8

*Capacity purchases in 2023 and 2024 have already been completed

CETA Portfolio Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							103
2026			100/100				133
2027		150	100/100				
2028		150/300	100/100				488
2029	480	100	100/100				
2030		50	100				
2031			100	295			
2032		50	100				
2033			100				
2034							
2035						50	
2036							
2037		100					
Total	480	900	1200	295	0	50	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	10.3	11.3
2024	10.2	11.1
2025	13.9	15.2
2026	21.4	23.3
2027	27.7	30.2
2028	33.0	36.0
2029	37.4	40.7
2030	40.8	44.4
2031	41.0	44.6
2032	40.7	44.3
2033	40.1	43.7
2034	39.2	42.7
2035	38.4	41.8
2036	37.4	40.7
2037	36.3	39.5

*Capacity purchases in 2023 and 2024 have already been completed

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ECR Portfolio Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							78
2026			100/100				43
2027			100/100				
2028		150/300	100/100		200		339
2029	240	150/150	100/100				
2030			100				
2031		150	100				206
2032		150	100			200	
2033			100				
2034							
2035							
2036		50					
2037							
Total	240	1100	1200	0	200	200	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	8.6	9.3
2024	5.5	6.0
2025	5.6	6.1
2026	10.6	11.6
2027	15.2	16.5
2028	19.2	20.9
2029	22.7	24.7
2030	25.5	27.8
2031	30.5	33.2
2032	34.8	37.9
2033	38.3	41.8
2034	41.3	44.9
2035	43.7	47.6
2036	45.4	49.5
2037	46.6	50.8

*Capacity purchases in 2023 and 2024 have already been completed

KENTUCKY POWER

NCR Portfolio Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	Solar + Storage	4hr – Li Ion Battery	Capacity Purchase
2023							70*
2024							80*
2025							78
2026			100/100				60
2027		50	100/100				
2028		150/100	100/100				494
2029	480					100	
2030							
2031				295			
2032							
2033							
2034							
2035						50	
2036							
2037							
Total	480	300	600	295	0	150	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	13.0	14.2
2024	16.1	17.6
2025	23.6	25.7
2026	33.6	36.6
2027	40.9	44.6
2028	46.9	51.1
2029	51.8	56.4
2030	55.6	60.5
2031	47.5	51.8
2032	41.5	45.2
2033	35.6	38.8
2034	30.1	32.8
2035	25.0	27.3
2036	20.4	22.2
2037	16.4	17.9

*Capacity purchases in 2023 and 2024 have already been completed

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Reference Winter Portfolio Sensitivity Detail

Utility-Scale New Build Additions by Year (Nameplate MW)							
Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Big Sandy Extension	20hr – Flow Battery	4hr – Li Ion Battery	Capacity Purchase
2023							405
2024							466
2025							454
2026			100/100			200	221
2027		50	100/100			150	52
2028		150	100/100		50	150	483
2029	480		100/100				
2030			100				
2031			100	295			
2032			100				
2033			100				
2034							
2035							
2036						200**	
2037							
Total	480	200	1200	295	50	500	

Utility-Scale New Build Additions by Year (Nameplate MW)		
Year	DSM Programs	Total +9%
2023	2.2	2.3
2024	5.7	6.2
2025	10.2	11.1
2026	17.1	18.7
2027	21.8	23.7
2028	25.7	28.0
2029	28.9	31.5
2030	31.4	34.2
2031	30.7	33.5
2032	31.4	34.2
2033	31.6	34.4
2034	31.4	34.2
2035	31.1	33.9
2036	30.5	33.2
2037	29.7	32.4

** Li-ion battery storage selected in 2036 to replace initial 2026 capacity after 10-year life

KP Optimization Results Summery - DSM Selection

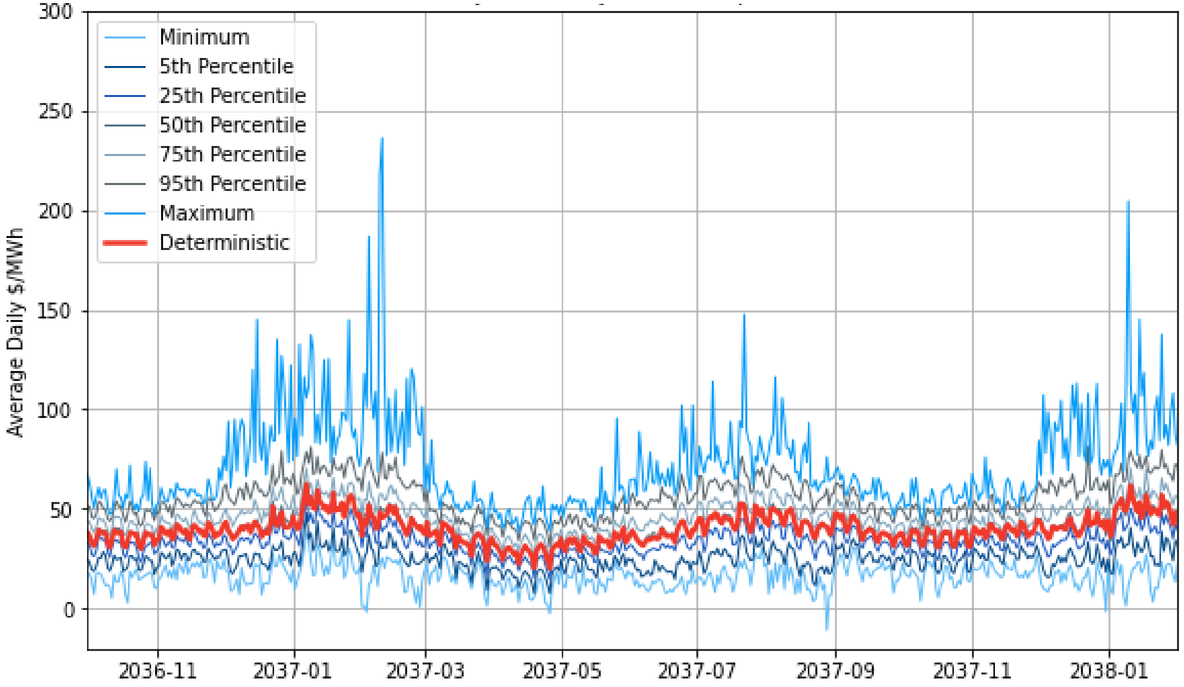
Program Year	DSM Program	REF	REF-HC	CETA	ECR	NCR
2023 - 2025	Residential – Low/Medium 23-25	X				X
	Residential – High 23-25					X
	Residential – Behavior 23-25					
	C&I – Low 23-25	X	X	X		X
	C&I – High 23-25					
2026 - 2030	Residential – Low/Medium 26-30	X		X		X
	Residential – High 26-30					X
	Residential – Behavior 26-30		X			X
	C&I – Low 26-30	X	X	X	X	X
	C&I – High 26-30					X
2031-2042	Residential – Low/Medium 31-42		X		X	
	Residential – High 31-42					
	Residential – Behavior 31-42					
	C&I – Low 31-42	X		X	X	
	C&I – High 31-42					

X = Selected
IQW implied across all time horizons and portfolios

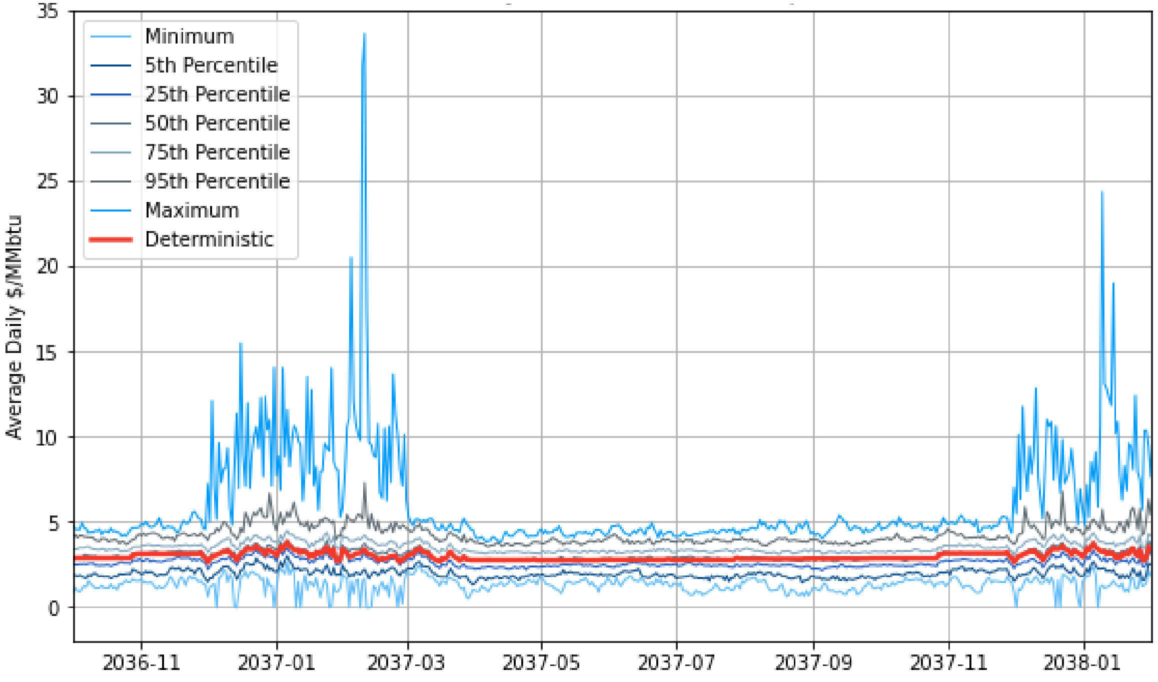
Commodity Price Volatility

The commodity price stochastic approach tests a wider range of price conditions than the ones considered in the deterministic scenarios, explicitly testing high-impact short-duration events that expose customers to costs.

Daily Power Prices (2037) - Example



Daily Natural Gas Price (2037) - Example

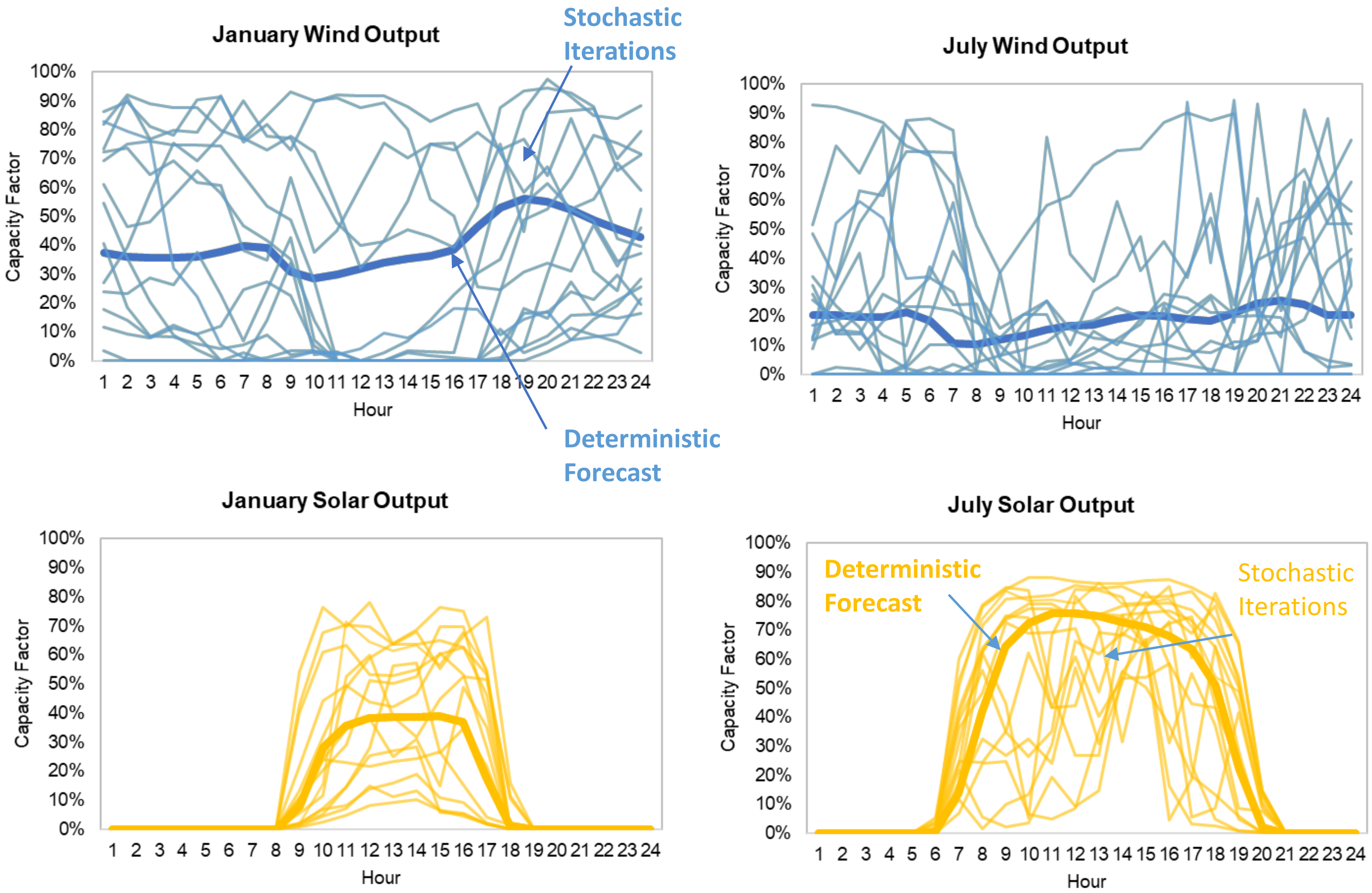


Renewable Output Volatility

Kentucky Power evaluated uncertainty in the output of wind and solar resources as part of the 2022 IRP analysis.

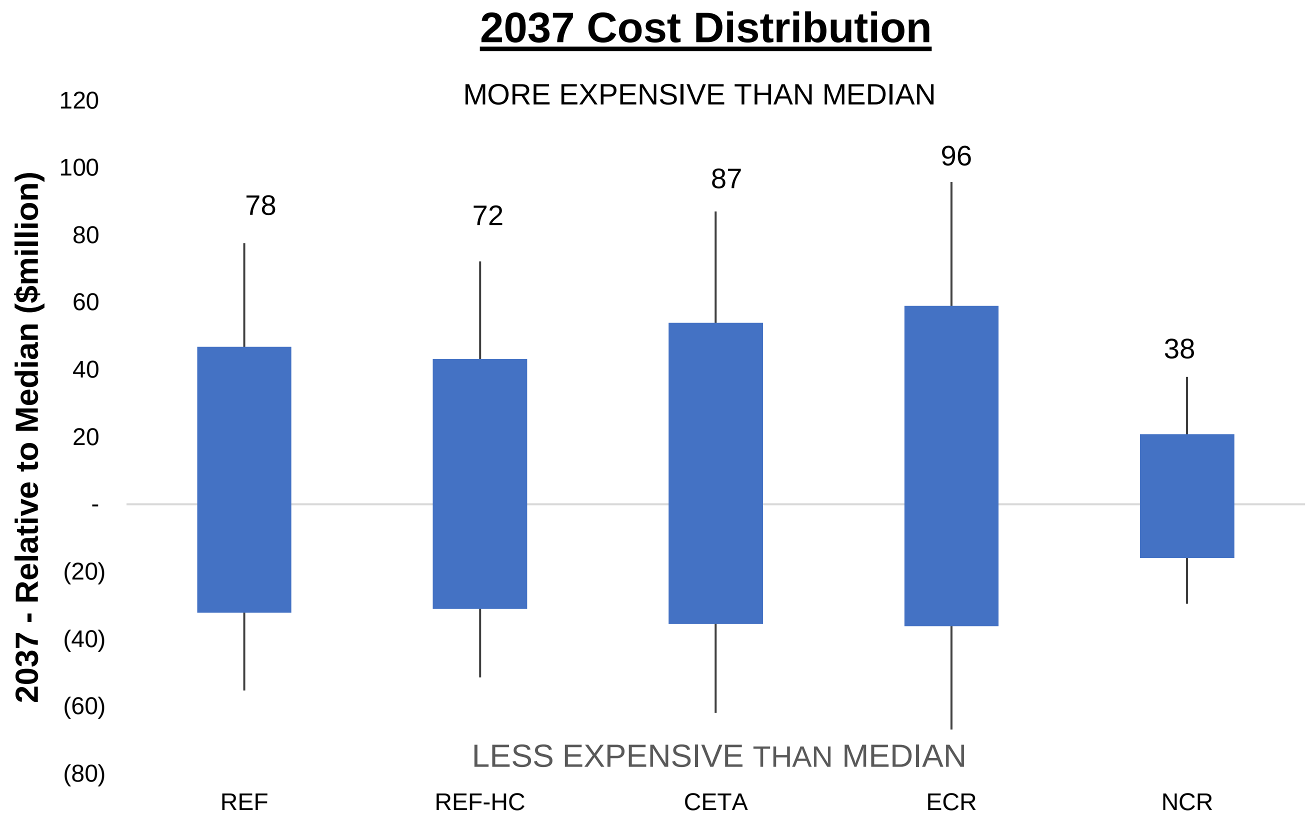
Representative hourly capacity factor shapes for wind and solar were developed using NREL's NSRDB and Wind Toolkit Databases.

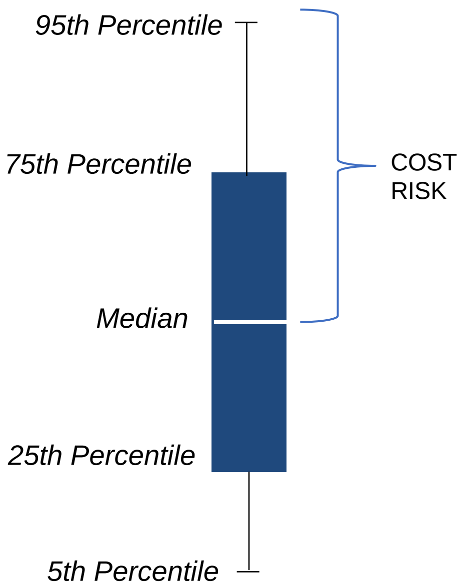
This result in a wider sample of production profiles that allow Kentucky Power to test periods of low output that coincide with high market prices (or vice versa).



Charles River Associates

Cost Risk





- Distributions range from $30-70M savings to $40-100M more expensive than median iteration.
- ECR has the widest distribution and the most cost risk (95th – 50th percentile) in 2037 due to a combination of the relatively large renewable resource and net sales exposure.
- The NCR portfolio have the least cost risk, followed by the REF High-Cost and REF portfolios.

COMMENTS ON KENTUCKY POWER COMPANY 2022 INTEGRATED RESOURCE PLAN BY KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Kentucky Industrial Utility Customers, Inc. (KIUC) appreciates this opportunity to respond to the July 14 Technical Conference held by Kentucky Power Company to discuss its upcoming Integrated Resource Plan (IRP) filing. KIUC recommends that the Company consider/explore the following additional scenarios in developing its formal IRP filing:

- Extending operation of Big Sandy 1 beyond 2030;
- Expansion of Big Sandy 1;
- Changing from an FRR Entity to an RPM Entity in PJM;
- Purchasing power, either via contract or by acquiring physical resources, from Riverside Generating Company;
- Co-ownership of new or existing generation resources with other utilities within Kentucky.

Consideration/discussion of the above-listed scenarios will bolster the comprehensiveness of the IRP filing and may result in better outcomes for Kentucky Power's retail customers.

Respectfully,

/s/ Michael L. Kurtz

Michael L. Kurtz, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
mkurtz@BKLlawfirm.com
jkylercohn@BKLlawfirm.com

July 19, 2022

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

DANIEL CAMERON
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT, KY 40601

July 29, 2022

Sent by email to *Kentucky_Regulatory_Services@aep.com*

Re: Kentucky Power Integrated Resource Plan Stakeholder Process

The Attorney General of the Commonwealth of Kentucky, by his Office of Rate Intervention, provides the following feedback in response to the stakeholder meeting conducted on July 14, 2022.

As an initial matter, the Attorney General thanks Kentucky Power for the opportunity to participate in the stakeholder process it has organized related to the development of its Integrated Resource Plan ("IRP"). Resource planning is more important than ever in the rapidly-evolving energy sector, and the resource planning process provided under Kentucky law is an important mechanism to ensure the utilities receive stakeholder input. Throughout this process, the Attorney General will provide feedback regarding aspects of the plan. As an initial matter, the following broad topics merit consideration.

First, regarding resource selection, Kentucky Power should employ an "all of the above" energy strategy that considers all resource types for selection and chooses the lowest-cost resources, which allows the utility to operate reliably for the benefit of its customers. An IRP must plan to provide an, "adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[1] Resources should not be excluded from consideration based on the extra-legal policy interests of the utility or its owner. Further, any plan that includes intermittent resources must include sufficient dispatchable resources to meet demand during the times when those resources are unavailable. Thus, a diversified resource mix is necessary to the extent intermittent resources are selected.

Second, regarding market volatility, Kentucky Power should model scenarios that allow for a complete self-supply of capacity and energy. Recent events demonstrate that over-reliance on RTO markets, while advantageous for ratepayers in certain circumstances, comes with risk. The Public Service Commission has indicated that, "[t]his Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[2] To the extent price and service risks to ratepayers can be minimized by full self-supply, Kentucky Power should model those scenarios accordingly. The Attorney General recognizes that, as recently as the 2019 IRP process, this Office advocated for the continuance of certain market purchases. Depending on the circumstances, some continued market purchases may be preferable, but efforts should be made in this process to determine whether full self-supply or bilateral contracting is

[1] 807 KAR 5:058(8).
[2] Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and its Member Distribution Cooperatives for Approval of Proposed Changes to the Qualified Cogeneration and Small Power Production Facilities Tariffs, Case No. 2021-00198 (Order of October 26, 2021 at 10).

preferable, especially during those years when the company is forced to address large capacity deficits.

Third, regarding reliability, Kentucky Power must demonstrate that its selected plan results in reliable service. As mentioned previously, its IRP must plan to provide an, "adequate and reliable supply of electricity."[3] Kentucky Power should plan investment and generation that results in service that is not interrupted by the technological limitations of intermittent resources or extreme weather events. The recent outages in California, Texas, and other jurisdictions demonstrate the importance of proper resource planning. Kentucky's utilities should learn from those mistakes in an endeavor to prevent them from occurring here.

Fourth, Kentucky Power should consider energy efficiency programs and other demand-side programs that could benefit ratepayers. An electron saved is an electron earned. If certain usage can be avoided, the expense associated with providing for that usage can be avoided as well, saving money for ratepayers. To the extent demand-side programs can be constructed to share the upside between the utility's shareholders and ratepayers, all scenarios should be considered.

The Attorney General appreciates Kentucky Power's willingness to consider these issues as it continues this stakeholder process. If properly planned and executed, an electric system that is reliable and affordable for ratepayers can be a foundation on which the people of Kentucky Power's territory will thrive economically. The Attorney

[3] 807 KAR 5:058(8).

General's goal is to assist the utility and other stakeholders in ensuring that the plan that results from this process keeps those objectives at its core.

Respectfully submitted,

DANIEL J. CAMERON
ATTORNEY GENERAL

J. MICHAEL WEST
LAWRENCE W. COOK
ANGELA M. GOAD
JOHN G. HORNE II
ASSISTANT ATTORNEYS GENERAL
1024 CAPITAL CENTER DRIVE, SUITE 200
FRANKFORT, KY 40601
PHONE: (502) 696-5433
FAX: (502) 573-1005
Michael.West@ky.gov
Larry.Cook@ky.gov
Angela.Goad@ky.gov
John.Horne@ky.gov

From: simon@southernwind.org
Sent: Wednesday, July 20, 2022 10:34 AM
To: Kentucky_Regulatory_Services
Subject: [EXTERNAL] Questions for IRP

Good morning,
Could you please provide the levelized cost of energy for all new proposed generation technologies?

Please provide the capacity factors used in the model and for the LCOE calculations.

Please provide additional data assumptions regarding hydrogen supply-side options.

-Simon

Simon Mahan | Executive Director
Southern Renewable Energy Association
simon@southernwind.org | (c) 337.303.3723
www.southernrenewable.org

COMMENTS ON KENTUCKY POWER COMPANY
2022 INTEGRATED RESOURCE PLAN
BY KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Kentucky Industrial Utility Customers, Inc. (KIUC) appreciates this opportunity to respond to the July 14 Technical Conference held by Kentucky Power Company to discuss its upcoming Integrated Resource Plan (IRP) filing. KIUC recommends that the Company consider/explore the following additional scenarios in developing its formal IRP filing:

- Extending operation of Big Sandy 1 beyond 2030;
- Expansion of Big Sandy 1;
- Changing from an FRR Entity to an RPM Entity in PJM;
- Purchasing power, either via contract or by acquiring physical resources, from Riverside Generating Company;
- Co-ownership of new or existing generation resources with other utilities within Kentucky.

Consideration/discussion of the above-listed scenarios will bolster the comprehensiveness of the IRP filing and may result in better outcomes for Kentucky Power's retail customers.

Respectfully,

/s/ Michael L. Kurtz

Michael L. Kurtz, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
mkurtz@BKLlawfirm.com
jkylercohn@BKLlawfirm.com

July 19, 2022

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

DANIEL CAMERON
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT, KY 40601

February 1, 2023

Sent by email to *Kentucky_Regulatory_Services@aep.com*

Re: Kentucky Power Integrated Resource Plan Stakeholder Process

The Attorney General of the Commonwealth of Kentucky, by his Office of Rate Intervention, provides the following feedback in response to the stakeholder presentation of January 25, 2023.

The Attorney General again thanks Kentucky Power for the opportunity to participate in the stakeholder process it has organized related to the development of its Integrated Resource Plan ("IRP"). Resource planning is important in the rapidly-evolving energy sector, and the resource planning process provided under Kentucky law is a way for utilities to receive stakeholder input.

After the presentation of January 25th, the Attorney General maintains many of the concerns previously communicated in his feedback of July 29, 2022. The Attorney General urges Kentucky Power to select a resource planning proposal that allows for reliable service at affordable rates. In order to achieve this end, Kentucky Power should employ an "all of the above" energy strategy that considers all resource types for selection and chooses the lowest-cost resources that allow the utility to operate reliably for the benefit of its customers.

Unsurprisingly, the planning portfolios presented at the January 25th Meeting demonstrate that Kentucky Power intends to increase renewable sources of generation. However, it is a surprise that wind, not solar, is the main form of renewable generation on which Kentucky Power intends to rely. The Kentucky Office of Energy Policy has observed that, "Kentucky has low wind speeds and, therefore, limited wind energy potential."[1] Thus, the planning portfolios presented by Kentucky Power raise many questions worthy of exploration in future proceedings.

First, selecting wind generation necessarily would require Kentucky Power to make substantial generation and transmission investments outside of the Commonwealth. Those investments would be subject to considerable regulatory and public scrutiny in jurisdictions whose leaders are unaccountable to the ratepayers of Eastern Kentucky. Kentucky Power should provide considerable treatment of these issues in its filings if it elects to proceed with a preferred plan that is highly dependent on wind generation. Kentucky ratepayers must not be held hostage by policymakers and stakeholders who have no incentive to do right by them.

Second, Kentucky Power should provide an analysis of the transmission costs that would accompany a shift to wind. In fact, transmission costs should be considered for all modeled technologies. Any generation technology proposal that fails to consider the transmission costs necessary for its full deployment is incomplete and does not represent an "apples to apples" comparison with competing technologies. If the modeling

[1] *Wind Energy in Kentucky*, https://eec.ky.gov/Energy/Documents/Wind%20Energy.pdf (last accessed January 26, 2023).

conducted by Kentucky Power failed to include appropriate transmission costs, that analysis should be undertaken.

Third, Kentucky Power asserted that, "combined cycles are not selected as an optimal solution under any of the market scenarios." This result is surprising given the recent decision by Kentucky Utilities Company and Louisville Gas & Electric to build two combined-cycle plants in Jefferson and Mercer Counties.[2] Nonetheless, all scenarios presented demonstrate that new simple-cycle combustion turbine gas generation will be required and will be relied on over the planning horizon. Kentucky Power should provide detailed treatment of why its modeling suggests investment in simple-cycle combustion turbine generation is preferred over combined-cycle generation.

Fourth, related jointly to the proposed reliance on wind energy and the acceptance of need for further gas investment, Kentucky Power should consider how its existing property and resources can be best utilized for the benefit of ratepayers. Kentucky Power should provide a thorough analysis for whether the Big Sandy site presents logistical benefits for siting a generation source that would reduce or eliminate the need to rely on the alternative wind generation that would necessarily be sited outside Kentucky. Reliance on wind resources outside the Commonwealth would entail increased transmission investment. Kentucky Power should demonstrate how it intends to be a good steward of the existing resources in which its ratepayers have invested over the years and how it intends to maximize the usefulness of those resources.

[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402.

Fifth, Kentucky Power needs to consider the reliability issues created by relying on intermittent resources. The presentation demonstrated that the modeled portfolios have similar outcomes, at least by some measures, as it relates to reliability. However, all of the modeled portfolios were heavily reliant on renewables in the out-years. As a point of information, Kentucky Power should compare those results to the operational flexibility of traditional dispatchable resources. Increased reliance on wind, or other renewable generation sources, creates obvious reliability impacts based on intermittency. This was clearly demonstrated, yet again, during the Christmas 2022 cold weather event that strained the electric grid across the country.[3] Even if utilities are able to narrowly avoid the worst case of prolonged outages during extreme, life-threatening conditions, reliance on intermittent resources provides no level of confidence that those resources can be relied on the next time around when the weather could present different challenges. As traditional generating assets retire and are not replaced, intermittent resources will have less dispatchable resources on which a utility can depend. In Kentucky, an IRP must plan to provide an, "adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[4] Any plan that includes intermittent resources must include sufficient dispatchable resources to meet demand during the times when those resources are unavailable. If Kentucky Power

[3] *Texas electrical grid remains vulnerable to extreme weather events*, https://www.dallasfed.org/research/economics/2023/0117 (accessed January 26, 2023). "Wind-power generation soared as temperatures plunged with the arrival of the cold front, with northerly winds exceeding 35 mph in many parts of the state. But similar to the 2021 deep freeze, wind speeds generally fell to 5 mph the day after the front passed, forcing the grid to rely primarily on thermal power plants and their associated supply chain."
[4] 807 KAR 5:058(8).

selects a preferred plan that relies heavily on renewables, it should demonstrate how it plans to maintain operational reliability despite its reliance on intermittent resources.

Sixth, regarding market volatility, Kentucky Power should consider whether its reliance on market purchases might increase risk to ratepayers. Recent events demonstrate that over-reliance on RTO markets, while advantageous for ratepayers in certain circumstances, comes with risk. The Public Service Commission has indicated that, "[t]his Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[5] To the extent price and service risks to ratepayers can be minimized by full self-supply, Kentucky Power should pursue those opportunities.[6]

Seventh, Kentucky Power should continue to consider energy efficiency programs and other demand-side programs that benefit ratepayers. An electron saved is an electron earned. If certain usage can be avoided, the expense associated with providing for that usage can be avoided as well, saving money for ratepayers. To the extent demand-side programs can be constructed to share the upside between the utility's shareholders and ratepayers, all scenarios should be considered.

---

[5] *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and its Member Distribution Cooperatives for Approval of Proposed Changes to the Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198 (Order of October 26, 2021 at 10).

[6] The Attorney General recognizes that, as recently as the 2019 IRP process, this Office advocated for the continuance of certain market purchases. Depending on the circumstances, some continued market purchases may be preferable, but efforts should be made in this process to determine whether full self-supply or bilateral contracting is preferable, especially during those years when the company is forced to address large capacity deficits.

If properly planned and executed, an electric system that is reliable and affordable for ratepayers can be a foundation on which the people of Kentucky Power's territory will thrive economically. The Attorney General's goal is to assist the utility and other stakeholders in ensuring that the plan that results from this process keeps those objectives at its core.

Respectfully submitted,

DANIEL J. CAMERON
ATTORNEY GENERAL

J. MICHAEL WEST
LAWRENCE W. COOK
ANGELA M. GOAD
JOHN G. HORNE II
ASSISTANT ATTORNEYS GENERAL
1024 CAPITAL CENTER DRIVE, SUITE 200
FRANKFORT, KY40601
PHONE: (502) 696-5433
FAX: (502) 573-1005
Michael.West@ky.gov
Larry.Cook@ky.gov
Angela.Goad@ky.gov
John.Horne@ky.gov

BOEHM, KURTZ & LOWRY
36 EAST SEVENTH STREET, SUITE 1510
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255

VIA E-MAIL

January 30, 2023

Brian K. West, Vice President
Regulatory and Finance
Kentucky Power Company
1645 Winchester Avenue
Ashland, Ky 41101
bkwest@AEP.com

Katie M. Glass, Esq.
Stites & Harbison PLLC
421 West Main Street
Frankfort, KY 40602-0634
kglass@stites.com

Re: 2022 Integrated Resource Plan

Dear Brian and Katie-

Attached please find Kentucky Industrial Utility Customers, Inc's (KIUC) Comments to Kentucky Power Company's Reference Portfolio presented at the January 25, 2023 Integrated Resource Plan (IRP) stakeholder meeting.

Very Truly Yours,

/s/ Michael L. Kurtz
Michael L. Kurtz, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew

Cc: (Via Email)
Kent Chandler, Chairman
Mary Pat Regan, Commissioner
Nancy Vinsel, General Counsel
J.E.B. Pinney, Esq., Executive Advisor
Justin M. McNeil, Esq., Executive Advisor
John G. Horne, II, Executive Director, Office of the Kentucky Attorney General
J. Michael West, Deputy Executive Director, Office of the Kentucky Attorney General
Lawrence W. Cook, Assistant Attorney General

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS INC's COMMENTS ON KENTUCKY POWER COMPANY's INTEGRATED RESOURCE PLAN

At its January 25, 2023 Integrated Resource Plan ("IRP") stakeholder meeting, Kentucky Power Company ("Kentucky Power" or "Company") presented a Reference Portfolio that contained the following:

- 480 MW Gas CTs (two 240 MW units) in 2029;
- 550 MW of Tier 1 and Tier 2 Solar additions in 2027-2037;
- 1,200 MW Tier 1 and Tier 2 Wind additions in 2026-2035;
- Extension of the useful life of the 295 MW Big Sandy 1 natural gas steam turbine in 2031;
- Market capacity purchases averaging 77.5 MW in 2023-2026, and a 495 MW market capacity purchase in 2028;
- DSM Programs starting at 12 MW in 2023 and ramping up to 36.3 MW in 2037.[1]

Kentucky Industrial Utility Customers, Inc. ("KIUC") offers its Comments to the Reference Portfolio.

Big Sandy 1 Extension. The extension of the useful life of 295 MW Big Sandy 1 natural gas steam turbine seems like an obvious, good decision. That plant has averaged a 32.6% capacity factor over 2017-2021 with a heat rate of approximately 10,200.[2] Big Sandy 1 provides a valuable energy hedge to PJM market energy prices and is an important part of Kentucky Power's Fixed Resource Requirement ("FRR") Plan. The plant will largely be depreciated in 2031 and has no significant known environmental upgrades. Therefore, the cost to ratepayers from the extension appears to be nominal.

[1] January 25, 2023 IRP Stakeholder Meeting Material ("IRP Meeting Material") at 83.
[2] Attachment 1.

Demand Side Management. The Demand Side Management ("DSM") plan appears reasonable, although the target could possibly be increased. The average residential customer on the Kentucky Power system uses a very high 1,232 kWh/per month.[3] Electric heating customers could especially benefit from increased weatherization and related programs. Some DSM programs can be labor-intensive as workers go house to house making energy efficiency improvements. To the extent that the present value economics of DSM versus capital-intensive alternatives are the same, then the labor-intensive option should be chosen because of the local economic development benefits.

Market Capacity Purchases. The 77.5 MW of average market capacity purchases in 2023-2026 for Kentucky Power to meet its PJM FRR capacity requirements are a necessary short-term bridge arrangement and appear reasonable.

However, there is a serious question about the assumed 495 MW market capacity purchase in 2028. If the market price for capacity in PJM in 2028 is $150/MW-day, then this would be a $27.1 million issue. Kentucky Power's energy and capacity entitlement to 50% of the 780 MW Mitchell 1 and 50% of the 780 MW Mitchell 2 extends at least until the *end* of 2028. No capacity purchase to replace Mitchell should occur at any time during 2028. The assumption that Mitchell replacement capacity will be needed beginning June 1, 2028 (the start of the new PJM Planning Year) is questionable and may be contrary to prior analysis presented by the Company. If such a capacity purchase is authorized, then all Mitchell fixed costs included in base rates (return, depreciation, fixed O&M, property taxes, etc.) would have to be simultaneously removed to avoid consumers paying for the same capacity twice.

[3] IRP Meeting Material at 6.

Beginning January 1, 2029 and thereafter, Kentucky Power will still maintain its 50% ownership interest in Mitchell. The sale/transfer pricing from Kentucky Power to Wheeling remains undetermined. But for ratemaking purposes, the Commission has made clear on two occasions that it expects the sale/transfer to be made at "*approximately net book value*"[4]. This ratemaking treatment would result in no stranded cost recovery from ratepayers, but could result in a write-off by Kentucky Power. The estimated net book value of Kentucky Power's share of Mitchell at December 31, 2028 is $343.1 million,[5] or more than a third of Kentucky Power's current equity capital. By continuing with the acquisition of Kentucky Power from AEP despite the Mitchell issue being unresolved, Liberty has assumed this risk which is or should be reflected in the acquisition sales price.

550 MW Solar. 550 MW of solar beginning in 2027 may be excessive for a system with a peak demand of about 1,100 MW and an average demand of about 650 MW. But at least this generation may be economically built in Kentucky Power's service territory. At $1,320/Kw,[6] the capital cost and rate base addition will be $726 million.

Natural Gas CT Versus NGCC. The assumption that two natural gas combustion turbines ("CTs") will be more economic than a natural gas combined cycle ("NGCC") for Kentucky Power post-Mitchell system is questionable. The operating characteristics of a 430 MW NGCC compared to two 240 MW CTs as well as EIA natural gas forecasted pricing were set forth in Kentucky Power's presentation, as shown below:[7]

[4] Case No. 2021-00421, May 3, 2022 Order at 16; Case No. 2021-00004, May 3, 2022 Order at 7.
[5] Case No. 2021-00421, Company Response to AG/KIUC 1-47.
[6] IRP Meeting Material at 77.
[7] January 25, 2023 IRP Meeting Material at 77 and 24.

Natural Gas CT	Natural Gas Combined Cycle
480 MW (two units)	430 MW
$753/KW	$1,194/KW
$361.4 million	$513.4 million
9,905 Heat Rate	6,431 Heat Rate
31% Capacity Factor	72% Capacity Factor
1,303,488 MWh Annual Energy Production	2,712,096 MWh Annual Energy Production
$39.8/MWh Energy Cost at $4/MCF Gas	$25.7/MWh Energy Cost at $4/MCF Gas

Based upon the Baseline Assumptions, the capital cost of a 430 MW NGCC is $152 million more than the capital cost of two 240 MW CTs. But the energy cost of the NGCC is $14.1/MWh lower assuming $4/MCF natural gas. The variable O&M costs of the CTs are about $2/MWh less and there are also some fixed cost savings associated with the CTs.[8] But the energy cost savings from the NGCC are still significant and likely more than offset the higher capital cost of the NGCC. NGCC units are given a very high-capacity value in PJM due to their low forced outage rates and high reliability.

The higher capacity factor and higher energy output of the NGCC also reduces the need for wind and solar energy and reduces reliance on market purchases. The NGCC would provide approximately half of Kentucky Power's annual retail energy requirements. Also, the NGCC's more efficient conversion of natural gas to electricity results in lower CO2 emissions per MWh compared to a CT. A 430 MW NGCC built at the site of the retired 800 MW Big Sandy 2 coal plant should require minimal additional transmission infrastructure. At least one gas transportation pipeline already serves that site. All of this calls into question the IRP assumption that two low-capacity factor CTs combined with significant wind and solar generation is lower cost and less risky than a high-capacity factor NGCC combined with in-state solar generation.

[8] IRP Meeting Material at 77.

1,200 MW Wind. The assumption of 1,200 MW of out-of-state wind generation appears to be a model driven result that lacks practicality. Rather than 1,200 MW of out-of-state wind generation, in-state generation should be favored because of the reliability benefits of local control, as well as the local economic development benefits (construction jobs and property taxes).

The transmission and interconnection costs of wind generation (and solar) is likely to be substantial. Transmission costs were not included in the cost per KW assumptions shown on page 77 of the IRP Meeting Material. A January 2023 DOE Study by the Lawrence Berkley National Laboratory, "Interconnection Cost Analysis in the PJM Territory", found that in 2017-2022 the interconnection costs in PJM for onshore wind was $136/KW compared to natural gas at $24/KW.[9] Solar was even higher at $253/KW.

Wind generation is also very difficult to site in the face of local opposition. A growing public concern is that wind generation is a technology that seeks to help the global climate, but at the expense of the local environment.

1,200 MW of wind generation will have a capital cost (before considering transmission) of $1,411/KW,[10] or $1.7 Billion. Yet the capacity value in PJM of 1,200 MW of on-shore wind is between 15%-20%, or 180 MW to 240 MW.[11] Using this out-of-state technology to serve load in Kentucky should be viewed skeptically.

Conclusion. Through the 2037 term of the study period, the Company seeks to have 2,525 MW of generation (480 MW CT, 550 MW solar, 1,200 MW wind and 295 MW Big Sandy extension), plus 36.3 MW of DSM, to serve a small service territory with a peak demand of about 1,100 MW and an average demand of about 650 MW. 2,525 MW of capacity is necessary to serve

[9] Attachment 2.
[10] IRP Meeting Material at 77.
[11] IRP Meeting Material at 30 and 37.

a peak demand of 1,100 MW (plus a reserve margin) because of the low-capacity value (Effective Load Carrying Capability("ELCC")) assigned by PJM to wind and solar.[12] And that capacity value declines over time. Especially for solar which drops from about 50% in 2023 to about 30% in 2037.[13]

Renewable generation does have the significant advantages of no variable energy costs, no CO2 emissions and significant Production Tax Credits ("PTC") and Investment Tax Credits ("ITC").[14] But this must be weighed against the high generation capital costs, high transmission costs and small capacity value. The capital cost/rate base additions under the Reference Portfolio are:

480 MW CT $361. 4 million
550 MW Solar $ $726 million (before transmission)
1,200 MW Wind $1.7 Billion (before transmission)
295 MW Big Sandy Extension $0.0

To put these rate base additions in perspective, Kentucky Power's current rate base at the end of 2021 for generation, transmission, and distribution totals about $2.0 Billion.[15] Transmission costs in the AEP East Zone are growing by at least 10% per year, and the Kentucky Power distribution system is in need of significant repair. Both of those things will put upward pressure on rates. With flat sales and increasing O&M and A&G costs, utilities can only grow earnings by growing rate base. So the motivation to build a capital intensive system focused on wind and solar is understandable. But the Commission must also consider the interests of the people and businesses of Eastern Kentucky.

[12] IRP Meeting Material at 36-37
[13] IRP Meeting Material at 36.
[14] IRP Meeting Material at 29.
[15] IRP Meeting Material at 6.

KIUC looks forward to working with the Company, Commission Staff, and interested parties on these important issues.

Respectfully submitted,

/s/ Michael L. Kurtz

Michael L. Kurtz, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
mkurtz@BKLlawfirm.com
jkylercohn@BKLlawfirm.com

COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

January 30, 2023

From: andrew mcdonald <andyboeke@yahoo.com>
Sent: Thursday, January 26, 2023 4:03 PM
To: Kentucky_Regulatory_Services
Subject: [EXTERNAL] Comments on KPC 2023 IRP process

To whom it may concern:

Thank you for the opportunity to participate in the KPC Stakeholder Meeting on January 25, 2023 in Frankfort. I appreciate the time taken by KPC to offer this stakeholder meeting and review their IRP process prior to filing with the Commission in March. Please consider the following comments with regards to the IRP.

DSM – Energy Efficiency

During discussion, KPC staff stated that they chose to take a modest approach to DSM-EE in the IRP. I encourage KPC to reconsider this approach and instead, pursue an ambitious DSM-EE strategy with the aim of achieving as much capacity and energy savings as possible throughout the 15 year planning period. KPC noted that they used as a reference point EE savings of 1% of annual sales. A recent study by ACEEE identified the highest-performing US utilities achieving more than 3% savings through EE programs.[1]

DSM-EE programs offer so many important benefits to KPC's customers, including reduced energy bills, home improvements, and greater comfort and indoor air quality. These programs have been proven repeatedly to be the least-cost "source" of energy.[2] In the face of the large capacity gap facing KPC, aggressively pursuing DSM-EE programs should be a cornerstone of KPC's planning, to minimize costs to customers and provide them with the most benefits.

This is especially important considering the sub-standard housing stock and poverty in KPC's territory. DSM-EE programs have even greater potential in Eastern Kentucky than other parts of the country, because the housing stock is already so much less efficient than in other regions. DSM-EE investments will provide direct benefits to the overall quality of life of the families and communities served by KPC.

Based on the presentation, it was unclear if KPC has produced a DSM Market Potential Study for its specific territory. If not, I would urge the Company to do so, due to the unique characteristics of this region.

During the presentation it was stated that the IRP planning process incorporated the incentives provided by the Inflation Reduction Act (IRA). However, it was unclear to what extent these incentives were factored into the DSM-EE analysis. The IRA offers a great many substantial incentives for EE and distributed energy resources which should be leveraged by KPC to enhance and expand its DSM-EE programs. If these were not included within a GDS Market Potential Study for KPC's specific territory, this should be done.

On-Bill Financing Programs

I recommend KPC to analyze developing an on-bill financing program as one of its DSM-EE offerings. On-bill financing programs (aka. Inclusive Utility Investments) provide a comprehensive solution that addresses the key barriers that prevent people from participating in and benefiting from DSM-EE programs. On-bill financing enables investments in whole-home, comprehensive improvements that can achieve dramatic utility bill savings. They include third-party energy audits and verification, to ensure quality. They open up DSM-EE opportunities to a much broader segment of the population, especially lower-income families and renters, who often cannot access other programs. By tying repayment of the investment to the meter, rental properties can more easily be renovated. These programs have been delivered with great success by many utilities.

In sum, KPC should treat DSM-EE programs as an essential resource, on par with supply side resources, and recognize that they offer many direct benefits to their customers.

Distributed Energy Resources

During the January 25 meeting, I asked how distributed energy resources (DERs) were considered in the planning process. The response was that it was incorporated into the load forecast and not considered within the supply-side resource planning.

I recommend evaluating net metering and DERs as resources on par with DSM-EE and supply-side resources. Net metering has many similarities to traditional DSM programs like home insulation and lighting retrofits – the resource is deployed at the customer-meter level, reduces the customer's energy requirements, provides direct benefits to the participating customer, and in the aggregate provides measurable energy and capacity savings for the utility. If treated as a resource on par with traditional DSM programs and supply-side resources, net metering may be found to be a very cost-effective and substantial resource option.

Consider that in LG&E-KU's 2021 IRP, they noted that net metering had the potential to supply more than 500 MW of new capacity by 2030, if the total capacity were allowed to grow beyond 1% of annual peak demand. [3] Statute enables utilities to stop offering net metering service after the installed capacity of net metering systems reaches 1% of a utilities' annual peak demand. As LG&E-KU noted in their 2021 IRP, capping net metering growth at 1% would limit distributed solar capacity to well under 100 MW through 2036. However, enabling net metering to grow beyond 1% would enable distributed solar to supply more than 500 MW of capacity by 2030. As LG&E-KU acknowledged during the recent IRP proceedings, the 1% figure is not a cap, but a threshold that the utilities have the discretion to exceed.

Evaluating net metering as a resource similar to other DSM programs and permitting it to grow beyond the 1% threshold would open up hundreds of MW of additional, low-cost capacity that would be built by customers, on their own properties, using their own funds, at the distribution level. KPC should consider the benefits of this strategy to the distribution system (especially where these DERs include storage) and how it would provide large amounts of renewable power with no transmission costs or constraints.

Thank you for your attention to my concerns. Please feel free to reach out if I can provide any further information on these topics.

Footnotes:

1. 2020 Utility Energy Efficiency Scorecard, American Council for an Energy Efficient Economy, 2020, p. 26. https://www.aceee.org/research-report/u2004

2. https://www.aceee.org/topic/ee-as-a-utility-resource

3. Integrated Resource Plan, LG&E-KU, 2021, Volume I, p. 5-29.

Andy McDonald, MSc, CEM
Director, Apogee - Climate & Energy Transitions
Kentucky Solar Energy Society, board of directors
316 Wapping St., Rm. 204, Frankfort, Kentucky 40601
502-699-2553 office
www.ApogeeClimate.org

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ATTACHMENT 1

S&P Capital IQ PRO

Big Sandy | Plant Financials

Periods : Last Five Years

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operational Statistics					
Operating Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Summer Peak Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Winter Peak Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Net Generation (MWh)	563,707	624,804	1,062,894	912,638	550,541
Capacity Factor (%)	24.75	27.43	46.67	39.96	24.17
Heat Rate	10,266	10,056	9,976	9,908	10,297
Reported Plant Production Costs					
Fuel Expenses					
Fuel Expense ($000)	26,202	22,576	34,166	21,301	25,661
Fuel Expense ($/MWh)	46.48	36.13	32.14	23.34	46.61
Estimated Fuel Cost?	No	No	No	No	No
Non-Fuel Operating & Maintenance Expenses					
Operating Supervision and Engineering ($)	685,766	666,884	688,937	1,951,886	2,454,899
Steam Expense ($)	9,555	24,606	18,596	13,171	980
Steam Transferred (Credit) ($)	0	0	0	0	0
Electric Expense ($)	2,190	1,102	5,794	7,092	1,011
Miscellaneous Power Expenses ($)	3,672,070	3,603,051	4,403,950	2,264,865	1,601,775
Rental Expense ($)	0	0	0	0	0
Allowance Expense ($)	40,248	27,047	46,498	18,164	4,563
Non-fuel Operating Expense ($)	4,409,829	4,322,690	5,163,775	4,255,178	4,063,228
Maintenance Supervision Expense ($)	323,068	317,944	337,349	371,965	341,137
Maintenance of Structures ($)	866,070	668,180	935,620	1,046,307	764,631
Maintenance of Boiler Plant ($)	1,535,270	3,088,296	1,146,617	2,073,487	2,526,988
Maintenance of Electric Plant ($)	1,086,902	1,350,025	789,518	1,083,391	1,215,477
Maintenance of Other Plant ($)	885,833	869,077	760,373	521,476	616,314
Total Maintenance Expense ($)	4,697,143	6,293,522	3,969,477	5,096,626	5,464,547

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Maintenance Expense ($/MWh)	8.33	10.07	3.73	5.58	9.93
Unit Non-Fuel O&M ($/MWh)	16.16	16.99	8.59	10.25	17.31
Estimated Non-Fuel O&M Cost?	No	No	No	No	No
Production Costs and Ratios					
Total Operating & Maintenance Expense ($000)	35,309	33,192	43,299	30,653	35,189
Total O&M Expenses per MWh ($/MWh)	62.64	53.12	40.74	33.59	63.92
Variable Production Expense ($000)	28,056	24,721	36,030	23,186	27,570
Fixed Production Expense ($000)	7,253	8,471	7,269	7,467	7,619
Variable Production Expense per MWh ($/MWh)	49.77	39.57	33.90	25.41	50.08
Fixed Production Expense per kW-yr ($/kW-year)	27.90	32.58	27.96	28.72	29.30
SNL Modeled Production Costs					
Non-Fuel Non-Allowance Variable O&M Cost ($)	3,683,815	3,628,759	4,428,340	2,285,128	1,603,766
Allowance Costs ($)	40,248	27,047	46,498	18,164	4,563
Non-Fuel Variable O&M Cost ($)	3,724,063	3,655,806	4,474,838	2,303,292	1,608,329
Fuel Costs ($)	23,323,872	24,074,925	29,422,521	23,634,248	24,674,137
Variable O&M Cost ($)	27,047,935	27,730,731	33,897,359	25,937,540	26,282,466
Non-Fuel Variable O&M Costs per MWh ($/MWh)	6.61	5.85	4.21	2.52	2.92
Fuel Cost per MWh ($/MWh)	41.38	38.53	27.68	25.90	44.82
Fixed O&M Cost ($)	5,382,909	6,960,406	4,658,414	7,048,512	7,919,446
Fixed O&M Cost per kW-Year ($/kW-year)	20.70	26.77	17.92	27.11	30.46
Total Operating & Maintenance Expense ($)	32,430,844	34,691,137	38,555,773	32,986,052	34,201,912
Total Operating & Maintenance Expense per MWh ($/MWh)	57.53	55.52	36.27	36.14	62.12

Note: S&P Global Market Intelligence reports generation and fuel consumption at the power plant and prime mover level, gathered from the Energy Information Administration forms 923 and 906 (EIA 923/906). Data from these forms is provided in both a preliminary/monthly report and a final annual report. The EIA does not provide a formal deadline for publication. Monthly reports are published 3 to 6 months after month-end, and annual data may not be published for 24 months from year-end.

In the case of pumped storage facilities, Net Generation (MWh) represents the total generation before energy used for pumping.

Additional data is sourced from the Federal Energy Regulatory Commission Form 1 (FERC Form 1) and the Environmental Protection Agency's Continuous Emissions Monitoring Systems (CEMS). In the absence of current-year filings, S&P Global Market Intelligence utilizes regression analysis to generate cost estimates. Inputs to the model are taken from the EIA 923, FERC Form 1 and CEMS.

ATTACHMENT 2

January 2023

Interconnection Cost Analysis in the PJM Territory

Interconnection costs have escalated as interconnection requests have grown

Joachim Seel, Joe Rand, Will Gorman, Dev Millstein, and Ryan Wiser (Lawrence Berkeley National Laboratory); Will Cotton, Katherine Fisher, Olivia Kuykendall, Ari Weissfeld, and Kevin Porter (Exeter Associates)

Executive summary

Interconnection queues have grown dramatically throughout the United States. In PJM, the cumulative capacity of projects actively seeking interconnection more than doubled from 2019 through 2022. Based on available data on project-level interconnection costs from PJM, our analysis finds:

- **Project-specific interconnection costs can differ widely**, depending on many variables and do not have the shape of a normal distribution. For example, 95% of projects that have completed all required interconnection studies (“complete”) between 2020 and 2022 have costs under $200/kW, but 5 projects cluster around $400/kW and one project has interconnection costs of $3,728/kW. At the same time, 30% of this sample even have costs under $5/kW.

- **Average Interconnection costs have grown**. Costs for recent “complete” projects have doubled on average relative to costs from 2000-2019 (mean: $42 to $84/kW, median: $18 to $30/kW). For projects still actively moving through the queue (“active”), mean costs have grown even more in recent years, from $29/kW to $240/kW (2017-2019 vs. 2020-2022, median: $8 to $85/kW). Interconnection requests that ultimately withdraw from the queue (“withdrawn”) face the highest costs (mean: $599/kW, median: $244/kW)—likely a key driver for those withdrawals. All costs are expressed in real $2022 terms based on a GDP deflator conversion.

- **Broader network upgrade costs are the primary driver of recent cost increases.** Mean costs for local attachment facilities at the point of interconnection (POI) are similar for complete ($12/kW), active ($13/kW), and historical withdrawn projects ($15/kW), although POI costs have recently increased for projects that ultimately withdraw ($36/kW). Costs for broader network upgrades beyond the interconnecting substation explain most cost differences and have risen sharply since 2019, to $71/kW for complete projects and $227/kW for active projects. Among withdrawn projects, they make up 94% of the costs at $563/kW for recent projects.

- **Potential interconnection costs of storage ($335/kW), solar ($253/kW), and wind ($136/kW for onshore, $385/kW for offshore) have been greater than natural gas ($24/kW) projects in recent years** (2017-2022). Among completed projects recent interconnection costs for solar ($99/kW) and onshore wind ($60/kW) have increased compared to historical costs (2000-2016), while natural gas costs have decreased ($18/kW). Costs for active and withdrawn storage and solar hybrid projects are surprisingly high ($337/kW), but complete projects are much cheaper (storage: $4/kW, solar hybrid: $20/kW). Solar projects that ultimately withdraw had interconnection costs of $559/kW (equivalent to 36% of total project installed costs), compared with $267/kW (or 19%) for withdrawn onshore wind applicants.

- **Larger generators have greater interconnection costs in absolute terms, but economies of scale exist on a per kW basis.** Among all potential projects, costs fall from $292/kW for medium-sized projects to $230/kW for large and $80/kW for very large project sizes. The size efficiencies generally hold for POI and network costs, and across request types (complete, active, withdrawn). When accounting for fuel type, economies of scale seem limited to natural gas, solar, and onshore wind, and to complete projects only.

- **Interconnection costs vary by location**, with projects in the western part of PJM (Michigan and West Virginia) reporting lower costs irrespective of request status ($36-56/kW). Applicants in the east where available transmission capacity is more limited (North Carolina, New Jersey, and Delaware) have higher costs ($485-971/kW).

The cost sample analyzed here represents 86% of all new unique generators requesting interconnection in PJM from 2000 to 2022. While it is sufficiently robust for detailed analysis, much data is difficult to obtain for the public. The paucity of easily accessible interconnection cost data poses an information barrier for prospective developers, resulting in a less efficient interconnection process. We have posted project-level cost data from this analysis at https://emp.lbl.gov/interconnection_costs.

1. The interconnection queue more than doubled in capacity since 2019

At year-end 2021, PJM had 259 gigawatts (GW) of generation and storage capacity actively seeking grid interconnection. Capacity in PJM's queue is dominated by solar (116 GW) and, to a lesser extent, standalone battery storage (42 GW), solar-battery hybrids (32 GW), and wind (39 GW). PJM's queue also contains data for projects no longer seeking interconnection, both those that are in service (79 GW) and those whose applications have been withdrawn (432 GW) (Rand et al. 2022). PJM's queue has ballooned in recent years, with 2021's active queue increasing by 240% compared to year-end 2019. The capacity associated with interconnection requests is nearly twice as large as PJM's peak load in recent years (~155 GW) and, if a substantial share is built, it will likely exert competitive pressure on existing generation. But historically, most projects withdraw: only 27% of projects requesting interconnection from 2000 to 2016 achieved commercial operation by year-end 2021.

Since 2012, PJM has implemented numerous reforms to reduce delays and project cancellations, including queue cluster extensions (to avoid queue study overlap and associated restudies) and an alternate queue for projects under 20 MW (which had high withdrawal rates) (Caspary et al. 2021). In 2021, following the large increase in interconnection requests and multiple interconnection process workshops, PJM embarked on a queue reform that was recently approved by FERC (FERC 2022). The core changes aim at a faster and more efficient interconnection process with greater cost certainty. They include a clustered, "first-ready, first-serve" approach, size-based study deposits, and increased readiness deposits that are at risk when projects withdraw later in the study process. In an effort to clear the existing request backlog, PJM will adopt an "expedited process" for a transitional period, allowing projects with network upgrades under $5 million to be studied in a fast track. Going forward, projects that do not contribute to the need for network upgrades will be able to proceed quicker to a final interconnection agreement under "accelerated procedures" (PJM 2022b). PJM also launched a new public tool (QueueScope) in 2022 to facilitate the assessment of grid impacts of proposed generation before submitting interconnection requests, but information is limited to line loading changes and does not include potential upgrade costs (PJM 2022e).

2. Cost sample represents 86% of new generators requesting interconnection over the past decade

This brief analyzes generator interconnection cost data from 1,127 projects that were evaluated in interconnection studies between 2000 and 2022, equivalent to 86% of all new unique generators over that time period.

Our interconnection cost sample has two sources:

- All cost data that were accessible in the online PJM system as of July 2022: 1,072 projects (PJM 2022a).
- Cost data for 55 additional projects that were collected in 2018 and had since been removed from the online PJM system (Gorman, Mills, and Wiser 2019).

While the sample is sufficiently robust to enable detailed analysis of interconnection costs, it represents only a subset of the 7,419 projects that are listed in the queue. We a) focus on new generation facilities (excluding 1,101 projects that represent capacity upgrades to existing facilities); b) require at least a posting of a feasibility study (excluding 3,134 projects without such a study); and c) remove superseded queue projects that withdraw and later reapply (excluding 1,772 projects, see left panel in Figure 1). We were not able to analyze costs for projects entering the queue after March 2021, as insufficient time had elapsed for their associated interconnection studies and cost estimates to be completed. PJM interconnection cost data is accessible without "Critical Energy Infrastructure Information" (CEII) certification, and cost excerpts are posted in part online (PJM 2022d). However, for the purposes of this analysis it still required manual cost extraction from study pdfs averaging 30-50 minutes per project, equivalent to about 550 hours for the entire sample. The lack of easily accessible interconnection cost data poses an information barrier for prospective developers, resulting in a less efficient interconnection process. We have posted project-level cost data from this analysis at https://emp.lbl.gov/interconnection_costs.

Interconnection Request Status Definitions

Complete: These projects have completed all interconnection studies and progressed to (or completed) the interconnection agreement phase. This includes plants that are now in service.

Active: These projects are actively working through the interconnection study process, progressing from an initial feasibility study via a system impact study to a refined facility study.

Withdrawn: These interconnection requests have been withdrawn from the queue (cancelled).

The sample varies over time with respect to request status (see right panel in Figure 1). Data for completed projects goes back furthest in time (373 projects, 56.8 GW). Some projects ultimately withdraw from the interconnection process for a variety of reasons; our data includes 189 such projects (21.7 GW) that were studied mostly between 2018 and 2022. Projects that are still active in the interconnection study process were primarily evaluated between 2020 and 2022 (565 projects, 59.4 GW).

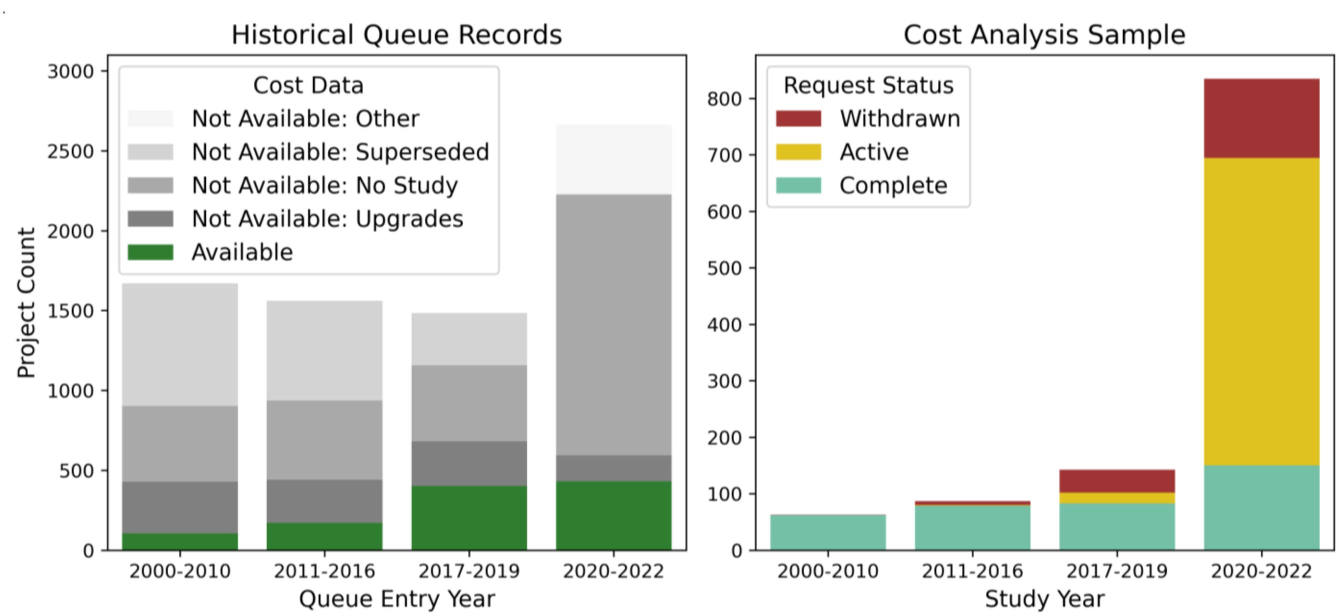

Figure 1 Sample: Availability of Cost Data Relative to Historical Queue Records *(left)*, **and Cost Data by Request Status** *(right). The left graph shows all historical generators seeking interconnection, indexed by their queue entry year. The right graph represents our cost analysis sample, with projects indexed by the year of the last available interconnection study. The remainder of this briefing will index projects by their study year.*

3. Interconnection costs have grown, driven by network upgrade expenses

Interconnection cost data were collected manually from public interconnection study reports, using the most recent study type available (feasibility studies, system impact studies, facility studies and interconnection agreements). The interconnection cost data summarized here are based exclusively on cost estimates in interconnection study reports, and do not include potential additional interconnection-related expenses that may be borne by a project developer.

We assume the reported costs refer to nominal dollars as of the time of the interconnection study, and present costs in real $2022 terms based on a GDP deflator conversion. We present interconnection costs in $/kW to facilitate comparisons, using the nameplate capacity of each project. We report simple means with standard errors throughout the briefing as detailed in the following textbox.

Interconnection Cost Metrics

The cost data do not have the shape of a normal distribution: many projects have rather low costs (or cost components), while a few projects have very high costs. We give summary statistics throughout this briefing as **simple means** to judge macro-level trends. Below is an example using completed project costs between 2017 and 2022. The histogram shows that more than 95% of all projects in this sample have interconnection costs under $200/kW, but five projects cluster around $400/kW (Figure 2, left), and two have costs of $712/kW and $3,728/kW (not shown). Medians (shown as dashed lines in the center of the boxplot) describe a "typical" project, with costs of $24/kW, but individual cost components cannot be added to meaningful sums. Means (Figure 2, right) can be influenced by a small number of projects with very high costs and are often higher than medians ($73/kW), but aggregated cost components can easily be added. We include the standard error of the mean ($\hat{\sigma}_{\bar{x}}$) as a measure of dispersion to give a sense of how scattered the data are. We point to median values in footnotes throughout the text.

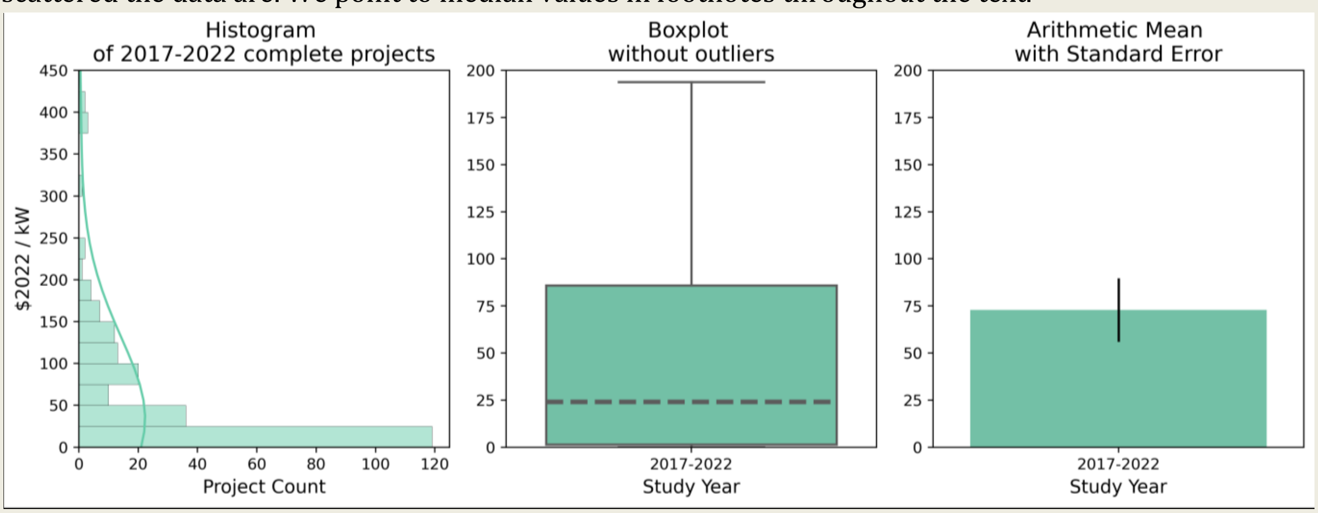

Figure 2 Interconnection Cost Metrics Example: Subsample of Projects Completing the Study Process, 2017-2022

The Appendix contains more information about the distribution of the cost data, showing box-plot versions of all graphs and illustrating the very wide spread in the underlying data from which the averages in this core briefing are derived.

3.1 Average interconnection costs have grown over time

Potential interconnection costs across all applicants increase in our sample after 2000. But combining all projects regardless of request status is problematic. Our cost sample composition changes over time, containing mainly completed projects in the early years but greater numbers of active and withdrawn projects in the later years (see Figure 1). Focusing on any given study cohort, one would expect that average interconnection costs would decline as projects proceed through the queue and high-cost projects naturally withdraw.

But the trend of increasing interconnection costs also holds true when accounting for the request status of a project applicant (see Figure 3). Among projects with completed interconnection studies, interconnection costs double from $42/kW before 2020 to $84/kW between 2020 and 2022 (the standard error of the mean $\hat{\sigma}_{\bar{x}}$ $5/kW and $26/kW respectively). Projects that were still actively moving through the interconnection queues saw costs increase eightfold, from $29/kW to $240/kW (2017-2019 vs. 2020-2022, $\hat{\sigma}_{\bar{x}}$=9&23). Projects that ultimately withdraw have seen costs more than double, from $255/kW to $599/kW (2017-2019 vs. 2020-2022, $\hat{\sigma}_{\bar{x}}$=187&103).[1] Costs for withdrawn projects are more than seven times the costs of "complete" projects between 2017 and 2022 ($521/kW vs. $73/kW, $\hat{\sigma}_{\bar{x}}$=91&17).[2]

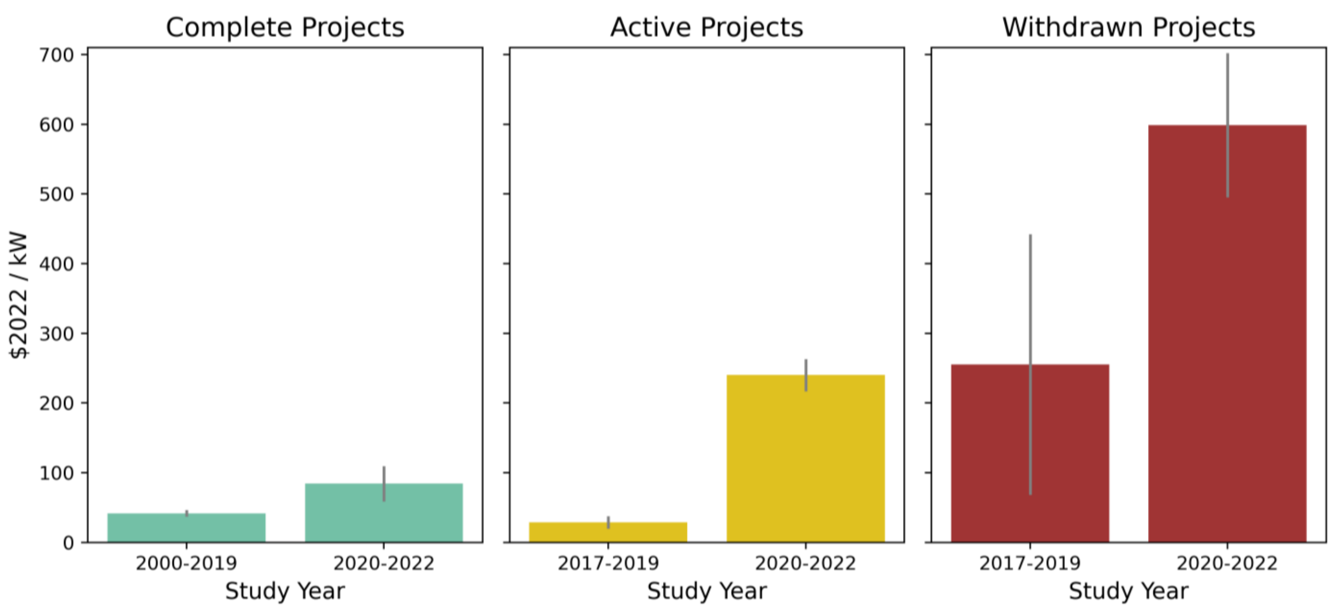

Figure 3 Interconnection Costs over Time by Request Status *(bars show simple means, gray lines represent standard error)*

3.2 Broader network upgrade costs are the primary driver of recent cost increases

We group costs identified in the interconnection studies into two large categories shown in Figure 4:

(1) Local interconnection costs describing investments at the point of interconnection (POI) with the broader transmission system. The FERC pro-forma Large Generator Interconnection Agreement (LGIA) refers to them as "Interconnection Facilities," while our study calls them POI costs.[3]

(2) Broader network upgrade costs.[4]

[1] Median costs nearly double for completed projects ($18 to $30/kW), grow eightfold for active projects ($8 to $85/kW), and increase by a factor of fourteen for withdrawn projects ($17 to $244/kW).

[2] Median costs for withdrawn projects are also more than six times the costs of complete projects over the period 2017-2022 ($156 vs. $24/kW).

[3] POI (Interconnection Facilities) costs usually do not include electrical facilities at the generator itself, like transformers or spur lines. Instead, they are predominantly driven by the construction of an interconnection station and transmission line extensions to those interconnection stations. This category is referred to as "Attachment Facilities" in PJM's interconnection studies.

[4] Network costs refer to two broad categories: Network Upgrade Charges (consisting of estimates for "Direct Connection Facilities," "Total Direct Connect Costs," "Direct Connection Network Upgrades," "Total Non-Direct Connection Costs," "Network Upgrade Facilities," "Non Direct Connection Facilities," and "Non Direct Connection Network Upgrades") and Other Network Costs (consisting of estimates for "Non-Direct Local Network Upgrades," "Allocation for New System Upgrades" (or System Network Upgrades), "Contribution for Previously Identified Upgrades," and "Other Charges").

Among the projects that successfully complete all interconnection studies, local upgrades at the POI are modest in PJM, accounting for only $12/kW (2017-2022, $\hat{\sigma}_{\bar{x}}$=2). In fact, POI costs have actually fallen by a few dollars since the early 2000s in this subsample. Network upgrade costs, on the other hand, can cause large cost additions for some projects and have grown in recent years (from $42/kW in 2017-2019 to $71/kW in 2020-2022, $\hat{\sigma}_{\bar{x}}$=10&25, Figure 4).[5]

Projects still being actively evaluated have similarly low POI costs that have remained stable at $13/kW in recent years ($\hat{\sigma}_{\bar{x}}$=1, Figure 4). However, network costs are the real cost driver: they are greater compared to completed projects in 2020-2022, again featuring in some projects with very high costs, and have risen in recent years from an average of $15/kW in 2017-2019 to $227/kW in 2020-2022 ($\hat{\sigma}_{\bar{x}}$=6&23, Figure 4).[6]

The situation is somewhat different for projects that ultimately withdraw from the interconnection process. POI costs were similar to active and complete projects in 2017-2019 at $15/kW ($\hat{\sigma}_{\bar{x}}$=4), but have more than doubled to $36/kW in 2020-2022 ($\hat{\sigma}_{\bar{x}}$=13). The required network upgrades are again what set the withdrawn projects apart: they doubled from an already high $240/kW to $563/kW ($\hat{\sigma}_{\bar{x}}$=185&103, Figure 4). The top 10% of network upgrade costs range between $928/kW and $10,164/kW.[7]

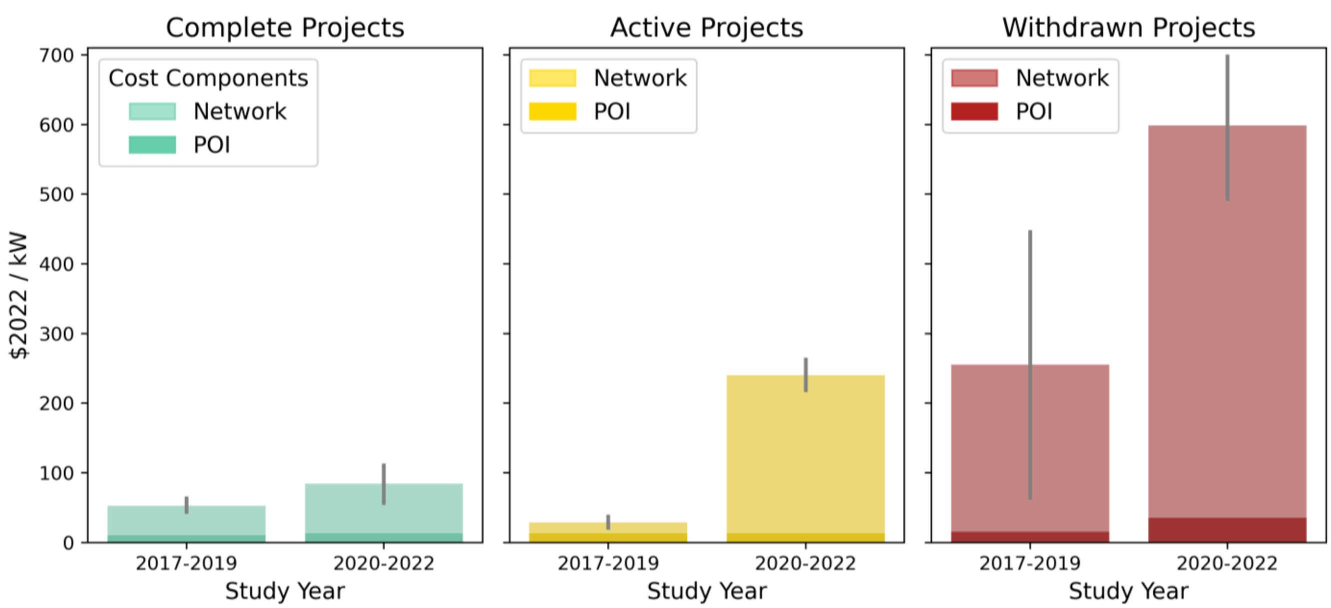

Figure 4 Interconnection Costs by Cost Category and Request Status *(bars: means, gray lines: standard error of total costs)*

3.3 Interconnection costs for solar and wind are larger than for natural gas

Interconnection costs vary by the fuel type of the generator seeking interconnection, both in terms of the magnitude and composition of cost drivers. The cost sample contains primarily solar (649), solar-battery hybrid (131), storage (114), natural gas (105), onshore wind (88), and offshore wind (11) projects, but also some hydropower (9), biomass (6), oil (4), coal (3), and nuclear (2) plants.

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[5] For complete projects in 2017-2022, median POI costs are $3/kW, median network costs are $16/kW (see also Figure 11 in the Appendix).
[6] For active projects in 2017-2022, median POI costs are $7/kW, median network costs are $68/kW (see also Figure 11 in the Appendix).
[7] For withdrawn projects in 2017-2022, median POI costs are $10/kW, median network costs are $136/kW (see Figure 11 in the Appendix). See, for example, a system impact study proposing upgrade costs of almost $599 million for a 51 MW solar project: https://www.pjm.com/pub/planning/project-queues/impact_studies/ag1129_imp.pdf

Offshore wind ($385/kW), storage ($335/kW), solar hybrid ($267/kW), solar ($253/kW), and onshore wind ($136/kW) costs are greater than natural gas ($24/kW) costs when looking at all recent projects, irrespective of their request status (see Figure 5, left).[8] High costs for storage and solar hybrid applicants seem surprising at first, as their operational flexibility should enable such projects to respond to transmission constraints if dispatched in response to local grid needs. But it appears that, despite storage's locational flexibility, many prospective projects have been proposed in regions with high transmission line loadings. Larger interconnection costs for batteries may also reflect a premium to qualify capacity in the PJM market, which assumes maximum storage discharge during peak load conditions.

The sample offers the longest time record for projects that complete interconnection studies. Looking at projects studied before and after 2017, we find that natural gas interconnection costs fall from $40/kW to $18/kW ($\hat{\sigma}_{\bar{x}}$=8&5). Costs grow for renewables: average solar costs increase from $54/kW to $99/kW ($\hat{\sigma}_{\bar{x}}$=12&26), whereas onshore wind costs rise from $23/kW to $60/kW ($\hat{\sigma}_{\bar{x}}$=5&29, see right panel in Figure 5). We only have solar hybrid projects with completed studies after 2020, but this subset seems to have much lower costs at $20/kW ($\hat{\sigma}_{\bar{x}}$=12) compared to stand-alone solar. The storage sample is small (2012-2016: n=4, 2017-2022: n=7), but average costs seem to have declined from $19/kW to $4/kW ($\hat{\sigma}_{\bar{x}}$=11&4), are much lower than for all proposed storage projects (including active and withdrawn ones), and are even lower than for natural gas.[9]

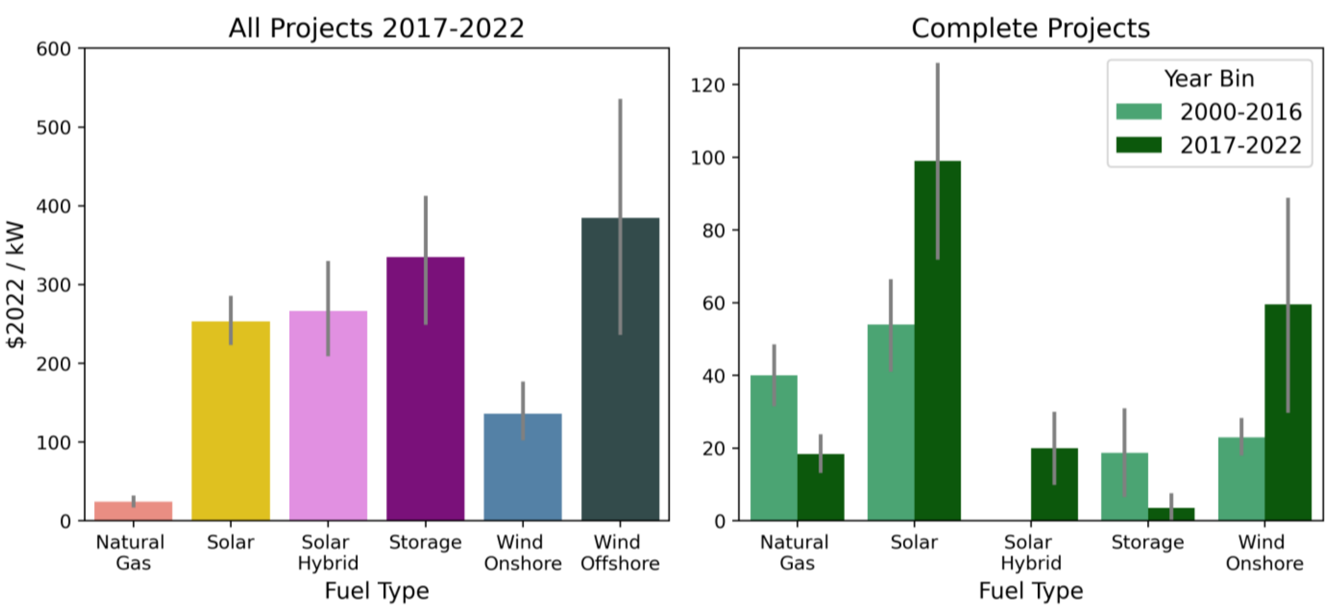

Figure 5 Interconnection Costs by Fuel Type (left) and Over Time for Complete Projects (right) *(bars: means, gray lines: standard error)*

For renewables that complete the study process, interconnection costs represent about 4% of total wind project installation costs in PJM (Wiser et al. 2022) compared to 7% of overall solar project installation costs in PJM in 2021 (Bolinger et al. 2022). Interconnection cost burdens are thus similar to those in MISO for solar (also 7%), but much less for wind (16% in MISO) (Seel et al. 2022). One potential driver of the larger

[8] $\hat{\sigma}_{\bar{x}}$ = 160, 78, 61, 28, and 34. The same trend is evident if we examine median interconnection costs for offshore wind ($190/kW), solar hybrid ($82/kW), solar ($82/kW), storage ($63/kW), and onshore wind ($46/kW) vs. natural gas ($8/kW), see Figure 13 in the Appendix.
[9] In median terms, the cost difference is less pronounced but the same trends hold: natural gas interconnection costs fall from $11/kW to $8/kW, solar costs grow from $33/kW to $43/kW, and onshore wind costs rise from $14/kW to $22/kW. The median solar hybrid costs are $0/kW for both year bins, for standalone storage they fall from $14/kW to $0/kW.

interconnection costs for wind and solar may be siting differences, as renewable generators are typically located in more rural areas with fewer nearby substations.

The breakdown of interconnection costs into POI and network costs also differs by fuel type. Figure 6 investigates the distribution of interconnection costs across all projects in our 2017-2022 sample. POI costs do not vary much by request status, except for rather low costs for complete wind projects ($3/kW) and unusually high costs for withdrawn solar projects ($39/kW). The average POI costs across the entire 2017-2022 sample is $16/kW.

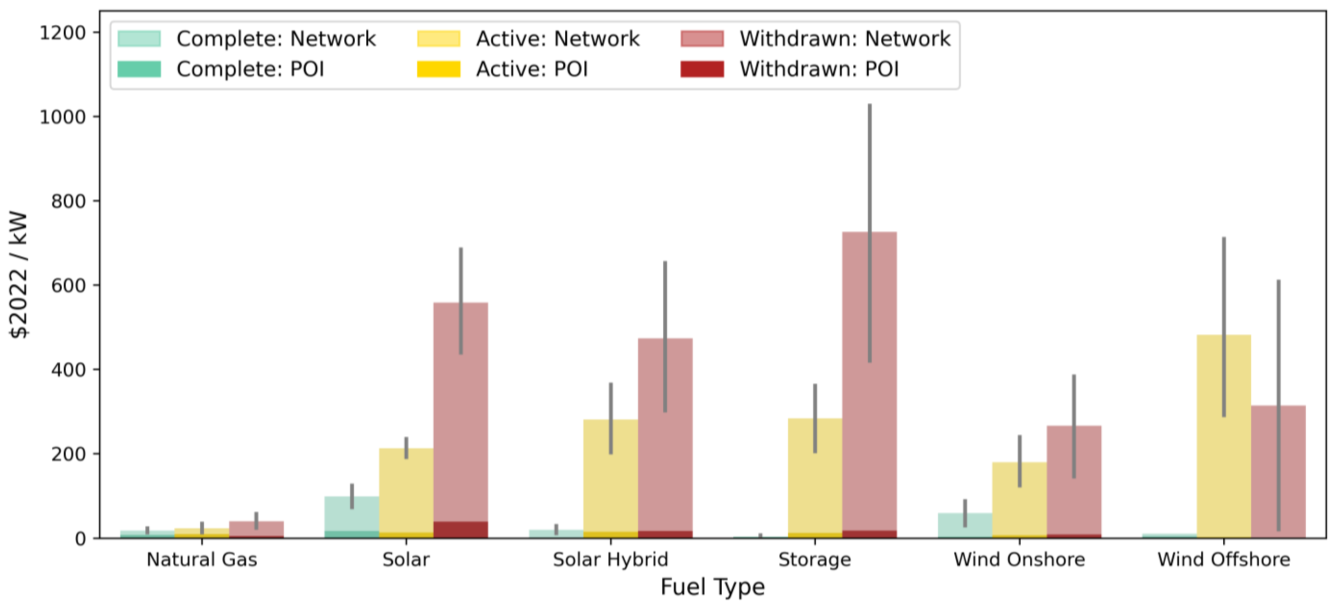

Figure 6 Interconnection Costs by Fuel Type, Cost Category, Request Status *(bars: means, gray lines: standard error of total costs, 2017-2022)*

In contrast, network costs increase dramatically for <u>active</u> and <u>withdrawn</u> projects relative to those that completed all studies. Completed storage projects had no network upgrade costs (n=7), while the average costs for withdrawn projects was $709/kW (n=17). Network costs were 25 times greater for withdrawn solar hybrid projects relative to complete projects ($457/kW vs. $18/kW). Withdrawn solar projects had six times greater network costs than complete projects ($520/kW vs. $82/kW), and withdrawn onshore wind projects had nearly five times the network costs of complete projects ($258/kW vs $56/kW).[10] The costs for "complete" offshore wind projects may not be representative, consisting of only one project, with data on active and withdrawn offshore wind projects showing relatively high costs of $482/kW and $315/kW, respectively.

High total interconnection costs among withdrawn solar projects of $559/kW ($\hat{\sigma}_{\bar{x}}$=124, or 38% of overall project installation costs (Bolinger et al. 2022)) may explain why some solar projects abandon the queue. Total interconnection costs of withdrawing wind projects are lower at $267/kW ($\hat{\sigma}_{\bar{x}}$=126), but would still account for 19% of installed project costs (Wiser et al. 2022).

[10] $\hat{\sigma}_{\bar{x}}$ of network costs for solar hybrid are 177 (withdrawn) & 9 (complete), for solar 123 & 25, and for onshore wind 128 & 29.

3.4 While larger generators have greater absolute costs, economies of scale exist on a per kW basis

Projects with larger nameplate capacity ratings have greater average interconnection costs in absolute terms. Between 2017 and 2022, all potential projects smaller than 20 MW have average costs of $2 million, which compares to $12 million for medium-sized projects (20-100 MW), $41 million for large (100-500 MW), and $65 million for very large (500-1750 MW) projects.

But these costs do not scale linearly on a per kW basis. Costs fall from $292/kW for medium projects to $230/kW for large and $80/kW for very large project sizes, respectively, suggesting economies of scale. Small projects have slightly lower average costs at $202/kW.[11] The size efficiencies generally hold both for POI and network costs: very large projects thus do not seem to bear atypically high interconnection costs or trigger unusually costly network upgrades. In fact, the larger initial investment may enable developers to preselect better sites that result in lower interconnection costs relative to project size.

Economies of scale also persist across the three different request statuses (see Figure 7). Very small projects again seem to have lower total interconnection costs. Medium-sized projects have usually the largest costs ($107/kW for complete, $246/kW for active and $660 for withdrawn projects) and the largest projects have only one-third to one-seventh of those costs.

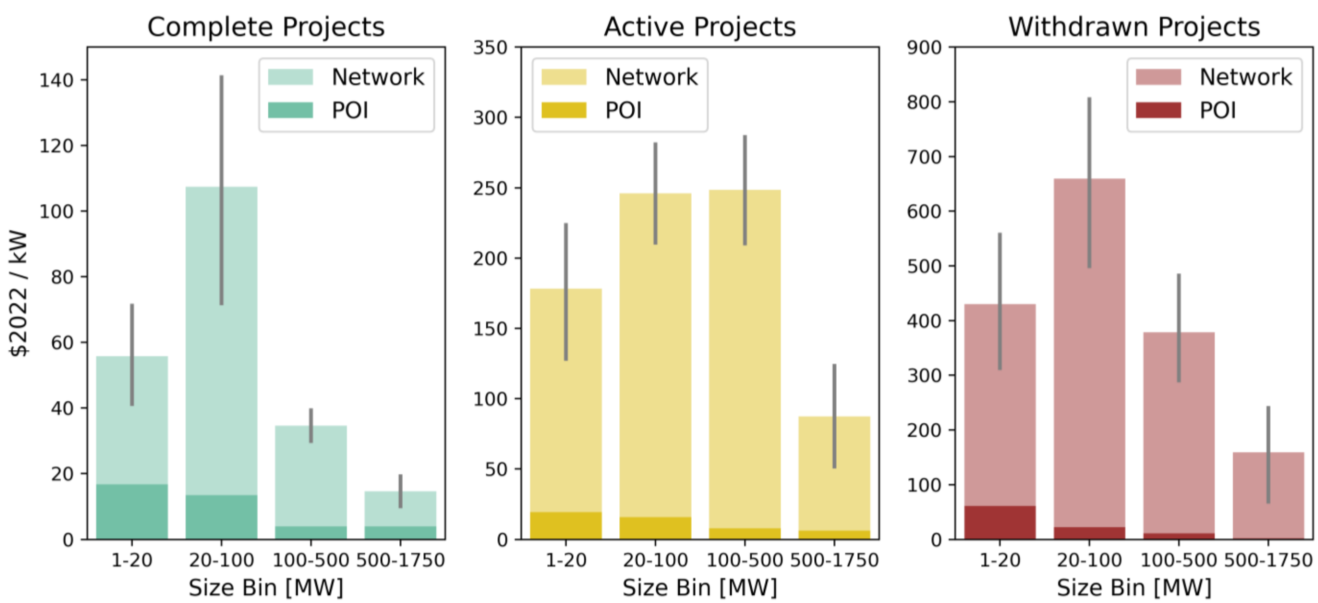

Figure 7 Interconnection Costs by Capacity and Request Status *(bars: means, gray lines: standard error of total costs, 2017-2022, y-axes differ by panel)*

Economies of scale do not hold consistently when accounting for fuel type, especially among withdrawn and active projects (see Appendix, Figure 14). Focusing only on complete projects, however, we find some evidence of declining costs with increasing project size for natural gas, solar, and onshore wind projects.

Fuel	1-20 MW	200-100 MW	100-500 MW	500-1750 MW
Natural Gas	$30/kW		$15/kW	$15/kW
Solar	$81/kW	$123/kW	$45/kW	$14/kW
Onshore Wind	$712/kW	$37/kW	$24/kW	

[11] $\hat{\sigma}_{\bar{x}}$ across size bins are 40 for small, 38 for medium, 31 for large, and 26 for very large projects. Median costs are $38/kW for small, $90/kW for medium, $78/kW for large, and $11/kW for very large projects (see Figure 15 in the Appendix).

We can only compare longer time trends for the subsample that has completed the interconnection studies, but find that larger projects have generally had lower costs compared with their smaller counterparts since 2012, on a per-kW basis.

Service Type

Generators seeking interconnection must choose between capacity (known in FERC's pro-forma LGIA as network resource interconnection service, NRIS) or energy service (known as energy resource interconnection service, ERIS). Capacity status reserves transmission capacity for the output of the generator during high load hours, for example allowing the project owner to have deliverable capacity that it can bid into resource adequacy markets. While capacity resources may still be curtailed during emergency events, they are treated preferentially in comparison to energy resources. This privilege comes with a cost however, as the generator may need to pay for additional transmission network upgrades. Energy service permits participation in the energy market and largely uses the existing transmission system on an as available basis.

The vast majority (95%) of all projects studied between 2017 and 2022 chose capacity as service type, a substantial increase over earlier years. Nearly all renewable projects opt for capacity status (wind offshore: 100%, solar: 99%, wind onshore: 98%) with the exception of solar hybrid projects (76%). Natural gas (95%) and storage (92%) stand-alone installations have slightly lower rates.

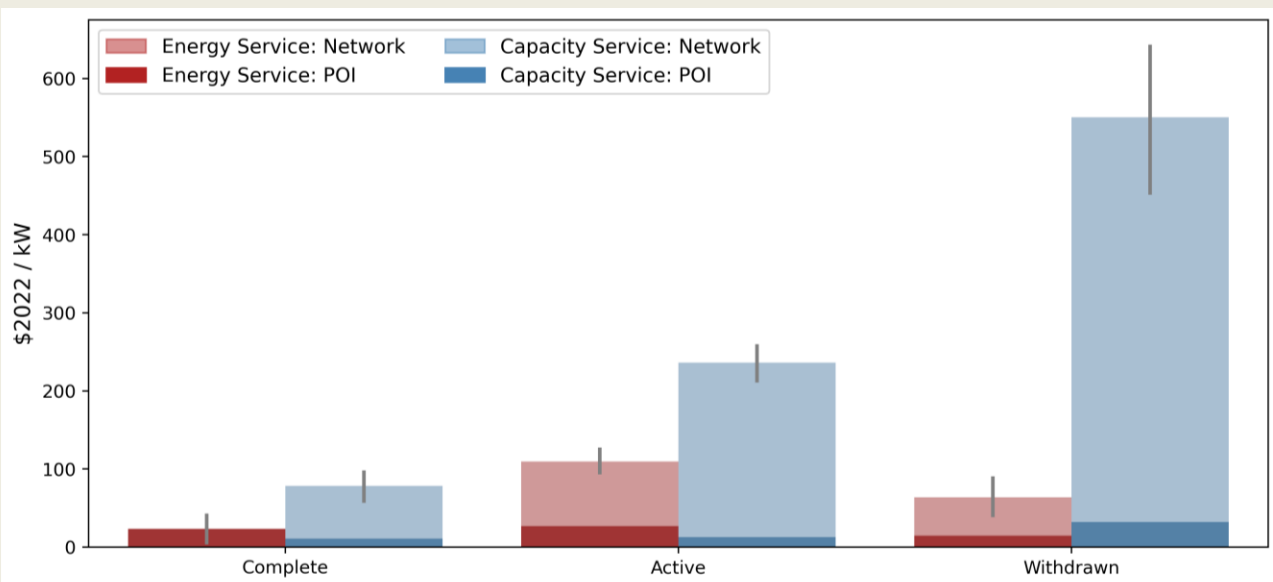

Figure 8 Costs by Service Type, Cost Category, Request Status *(bars: means, gray lines: standard error of total costs, 2017-2022)*

While POI costs are roughly similar, network upgrade costs are much higher for capacity than energy projects as one might expect, a trend that has increased in recent years. Capacity network costs across all request status were historically only slightly higher ($17/kW), but that differential grew to $206/kW between 2017 and 2022. Figure 8 inspects interconnection costs by request status and service type, and shows that among recent energy projects that complete all interconnection studies average network upgrade costs were $0/kW (compared with capacity: $67/kW). Energy projects that are still actively being evaluated are now assessed network upgrade costs of $83/kW (capacity: $223/kW), while withdrawn energy projects are billed $49/kW for network upgrades compared to $518/kW for withdrawn capacity projects.

3.5 Interconnection costs in eastern PJM states are generally higher than in the west

Interconnection costs also vary by location, with western projects in Michigan ($36/kW) and West Virginia ($58/kW) reporting overall lower costs across all projects studied between 2017 and 2022, irrespective of whether they ultimately complete the interconnection process. Eastern applicants in North Carolina, New Jersey, and Delaware, on the other hand, have high average interconnection costs ($485-971/kW). Overall, there is some alignment between states with high interconnection costs and states with little available transmission capacity and/or high levels of congestion, as indicated for example by higher zonal capacity prices (PJM 2022c), which tend to be located primarily in the eastern part of the ISO.

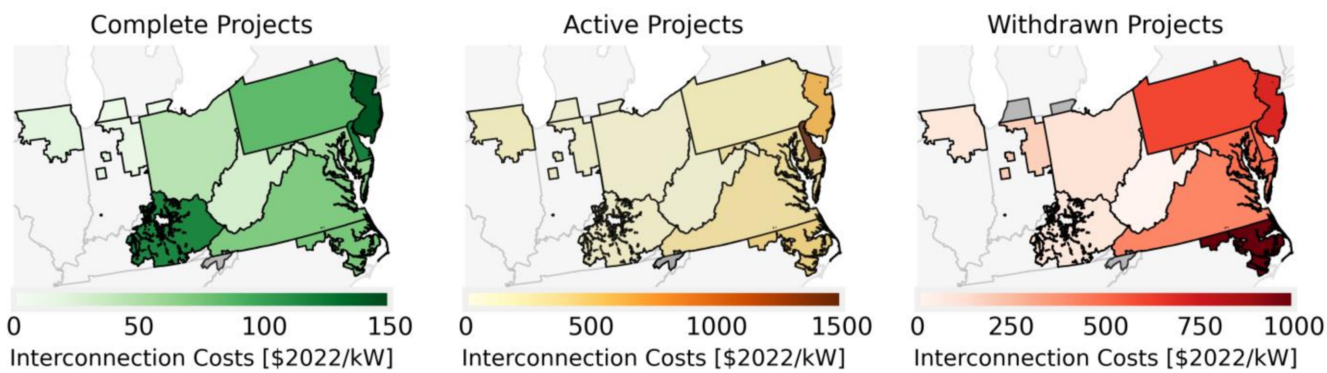

Figure 9 Interconnection Costs by State and Request Status, all Fuel Types *(means, 2017-2022, grey areas indicate no data)*

Figure 9 examines cost variation by state and project status request. Eastern states again have comparatively high interconnection costs among complete (New Jersey: $143/kW) and withdrawn projects (North Carolina: $1068/kW, New Jersey: $759/kW), while western states like Indiana and Illinois have lower costs for completed projects ($14/kW, $20/kW), as do Kentucky and Ohio for withdrawn projects ($88/kW, $108/kW). A seeming outlier is the high cost for completed projects in the west in Kentucky ($117/kW), but this is a small sample with only five observations consisting only of recent solar and solar hybrid projects interconnecting mostly to the small East Kentucky Power Cooperative.

Appendix Figure 18 to Figure 23 dive deeper into geographical cost distributions by fuel type, showing again higher interconnection costs in the east for solar, solar hybrid, and storage. Natural gas projects skew a bit differently, with higher costs both in the north (New Jersey, Ohio, and Pennsylvania) and south (Virginia). Onshore wind has higher costs in the north (New Jersey, Pennsylvania, and Illinois) than in the south. Delaware, New Jersey, and Virginia have higher interconnection costs for offshore wind than Ohio.

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For other interconnection related work, see https://emp.lbl.gov/interconnection_costs and https://emp.lbl.gov/queues
For the DOE i2X program, see https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange
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4. Appendix

This Appendix includes boxplot versions of the graphs in the core report, highlighting the broad distribution of interconnection costs that underlie the previously presented means. The boxplot median is highlighted with a bolder dashed line, and the lower and upper box line represent the 25th and 75th percentile. The lower/upper whiskers are 1.5x of the interquartile range below/above the 25th and 75th percentile. Not all outliers beyond the upper whiskers are shown in the graphs to preserve legibility but are included in the project-level cost data posted on our website (https://emp.lbl.gov/interconnection_costs). **Caution when comparing data between panels, as y-axes often differ** (to enable comparison of data within each panel).

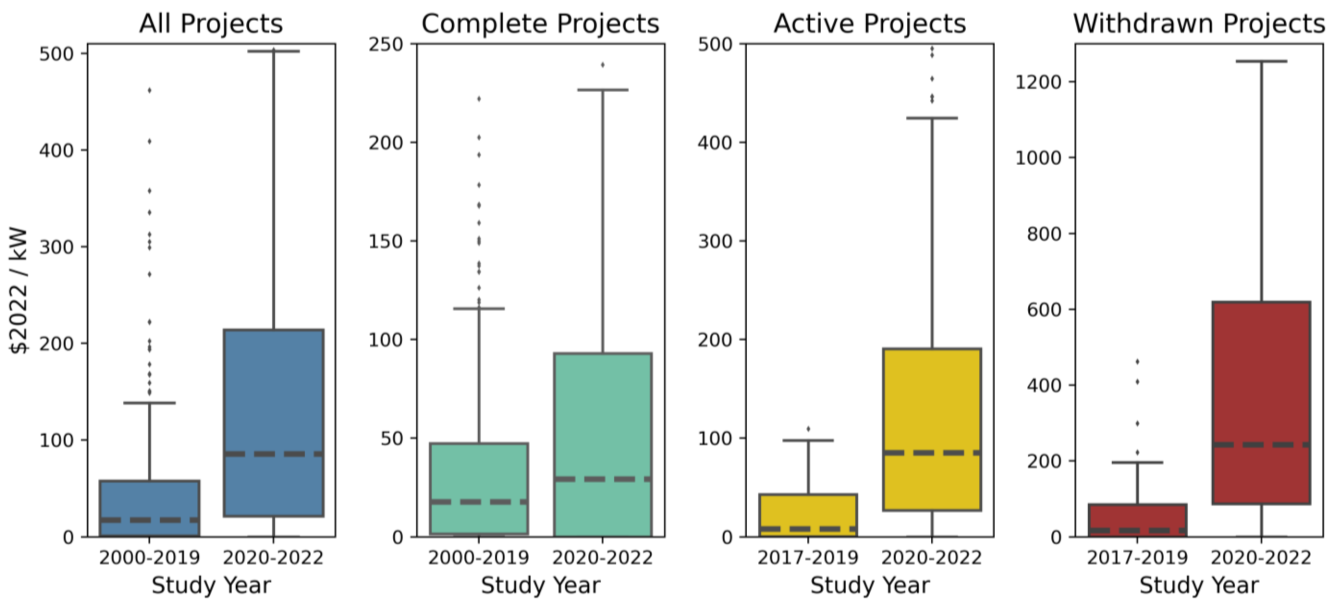

Figure 10 Interconnection Costs over Time by Request Status *(**y-axes differ by panel**, not all outliers outside 1.5x interquartile range are shown)*

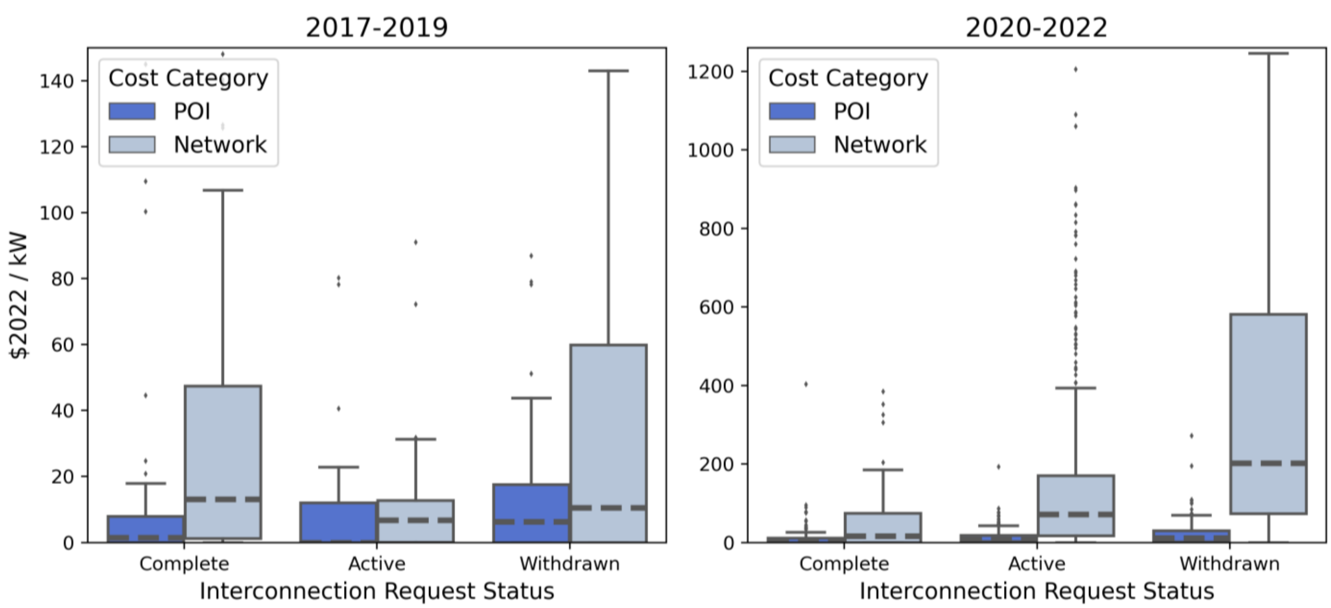

Figure 11 Interconnection Costs by Request Status and Cost Category *(**y-axes differ by panel**, not all outliers outside 1.5x interquartile range are shown)*

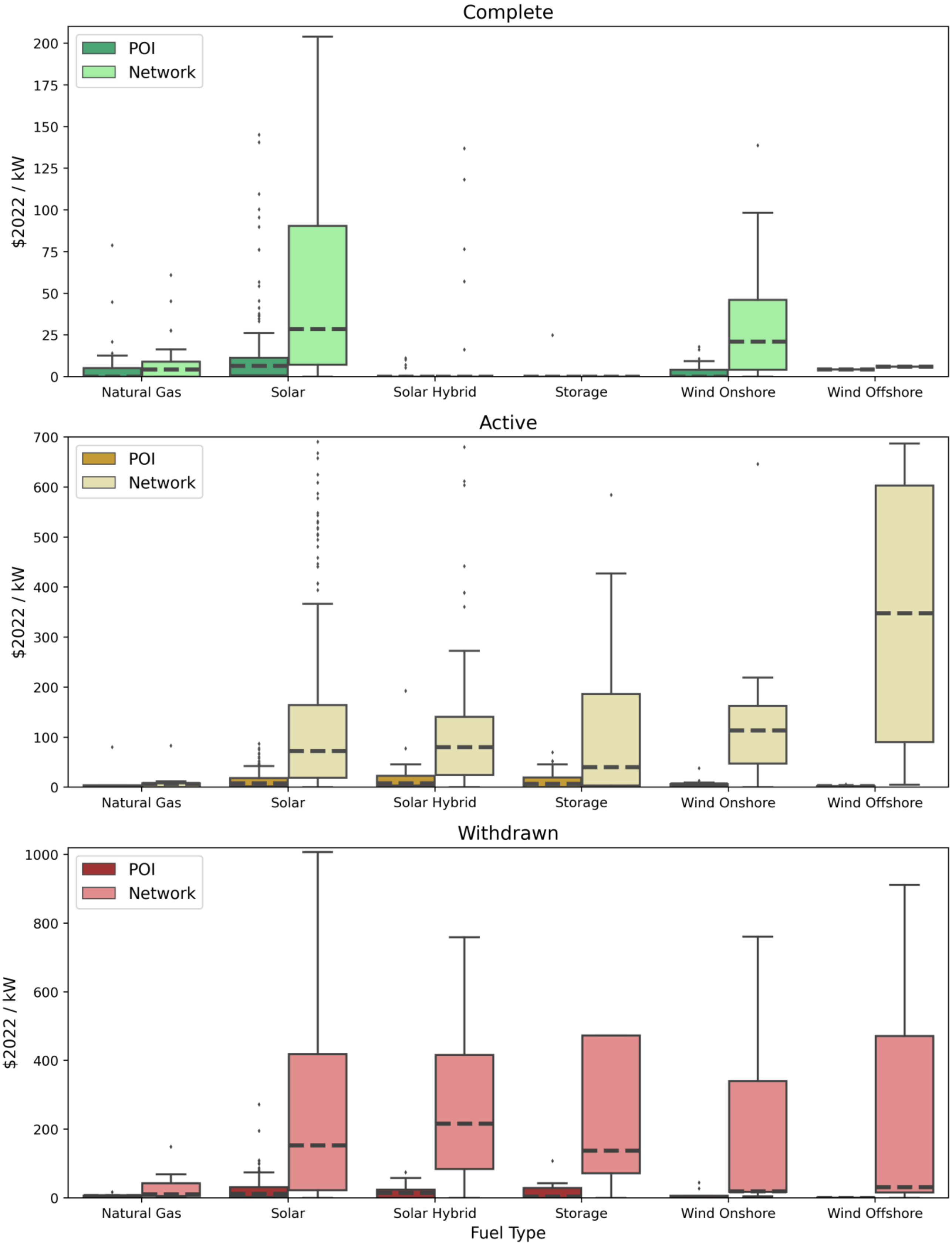

Figure 12 Interconnection Costs by Fuel Type, Request Status, and Cost Category *(**y-axes differ by panel**, 2017-2022, not all outliers are shown)*

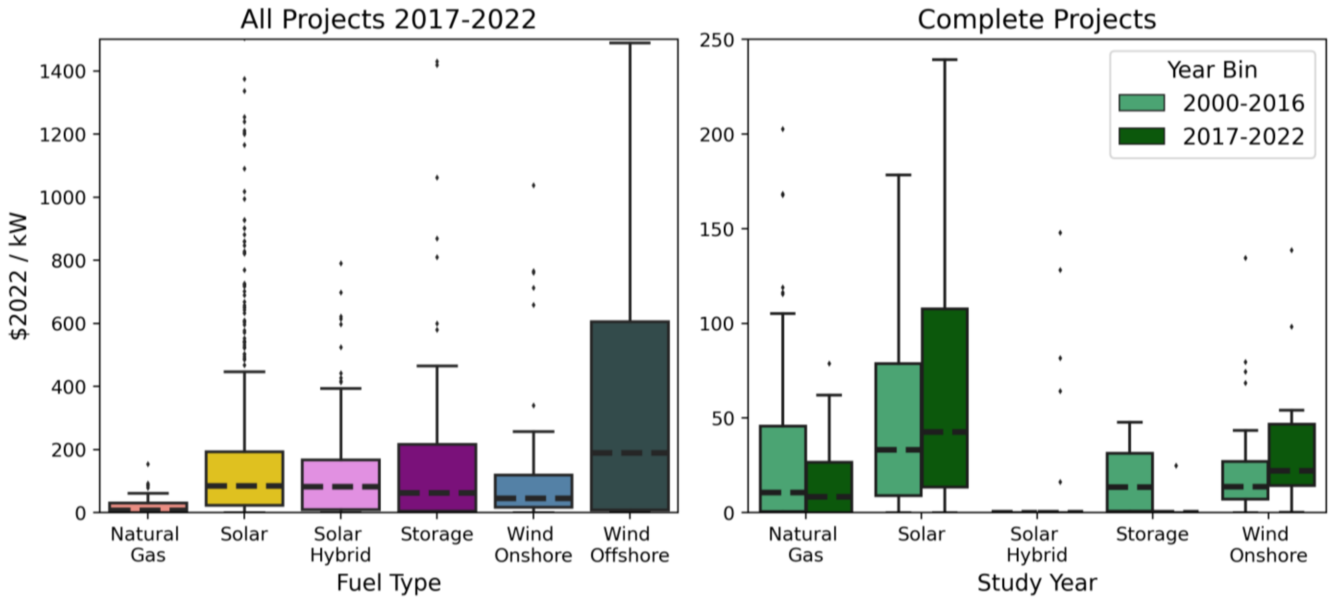

Figure 13 Interconnection Costs by Fuel Type (left) and Over Time for Complete Projects (right) ***(y-axes differ by panel****, not all outliers are shown)*

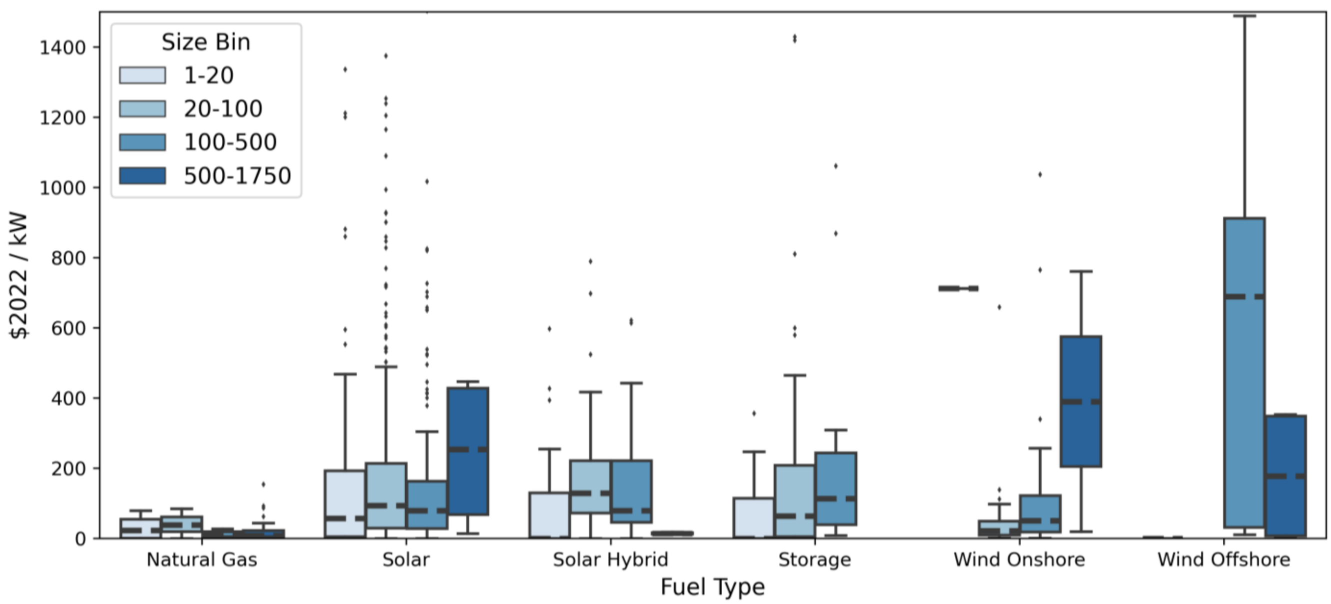

Figure 14 Interconnection Costs by Fuel Type and Size Bin *(2017-2022, not all outliers are shown)*

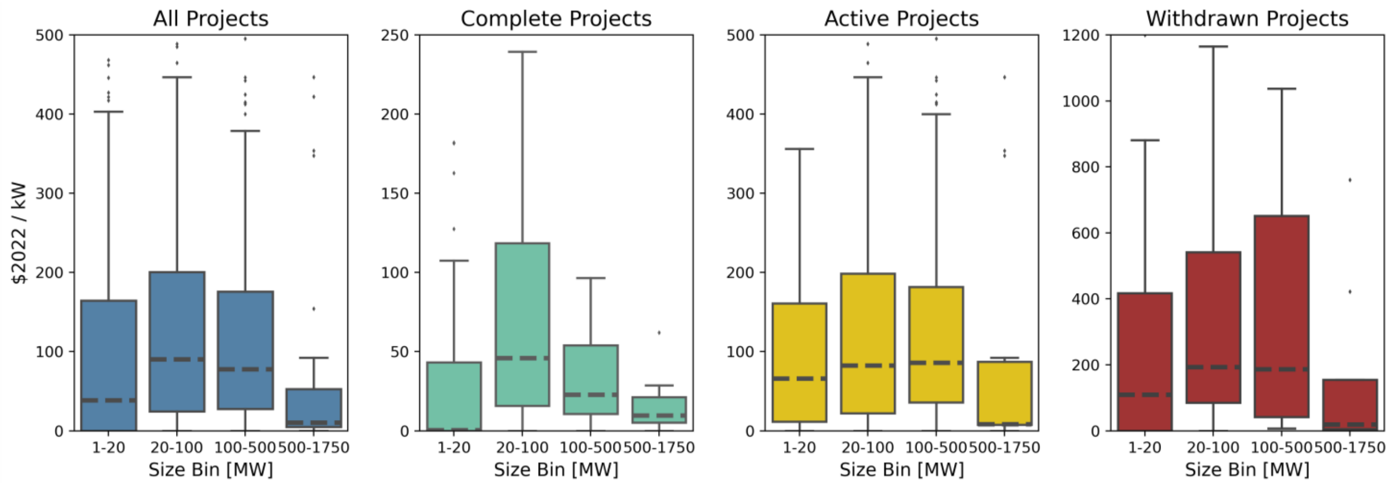

Figure 15 Total Interconnection Costs Request Status and Size Bin *(**y-axes differ by panel**, 2017-2022, not all outliers are shown)*

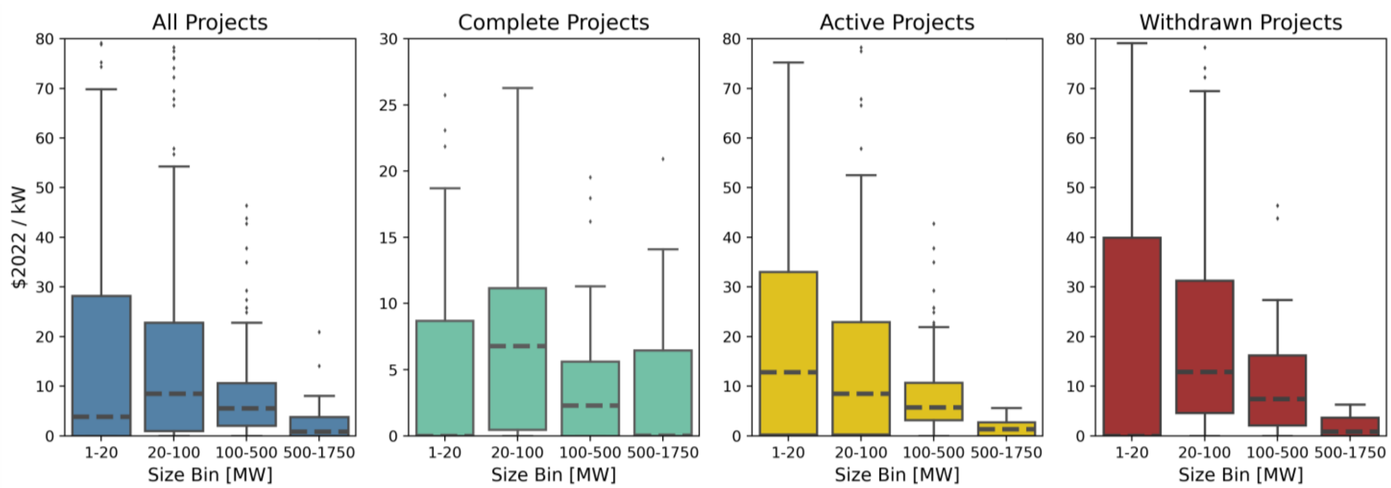

Figure 16 POI Interconnection Costs Request Status and Size Bin *(**y-axes differ by panel**, 2017-2022, not all outliers are shown)*

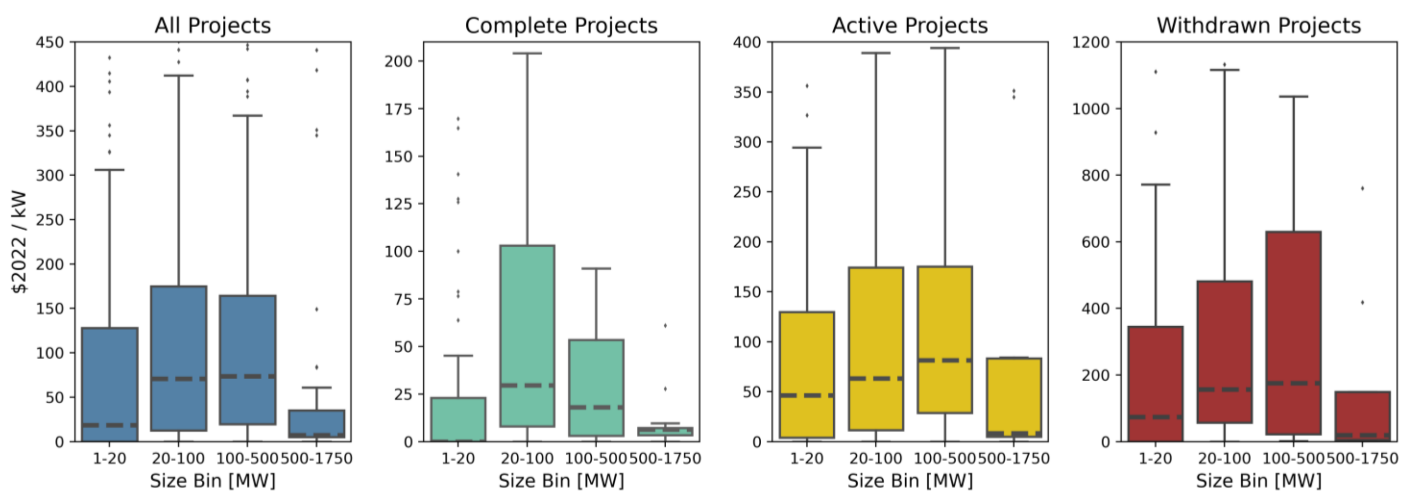

Figure 17 Network Interconnection Costs Request Status and Size Bin *(**y-axes differ by panel**, 2017-2022, not all outliers are shown)*

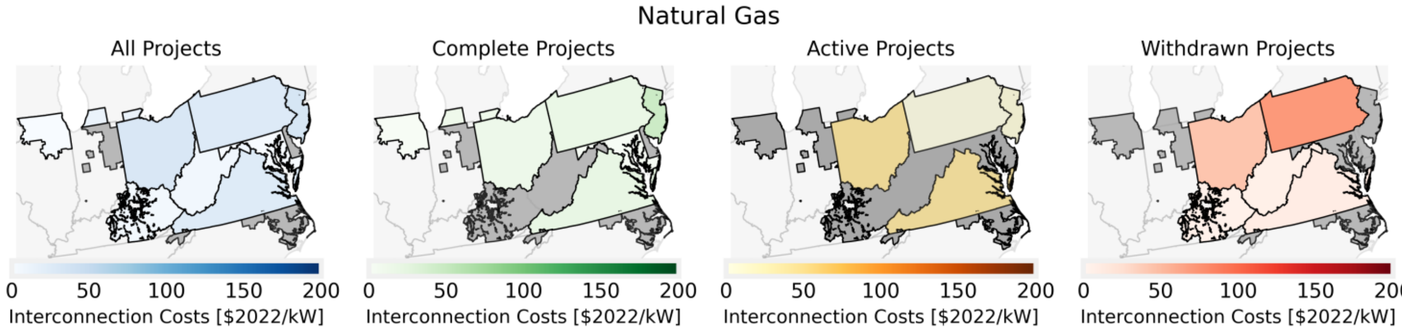

Figure 18 Interconnection Costs by State and Request Status: Natural Gas *(means, 2017-2022, grey areas indicate no data)*

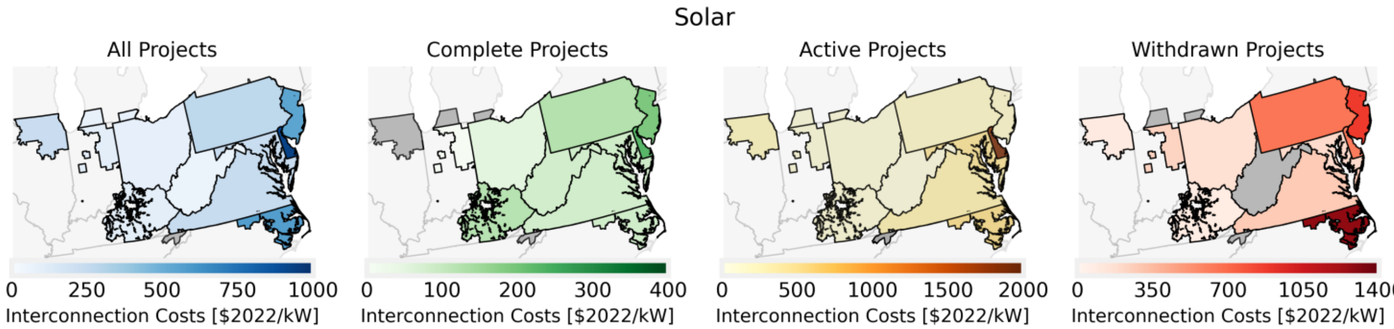

Figure 19 Interconnection Costs by State and Request Status: Solar *(means, 2017-2022, grey areas indicate no data)*

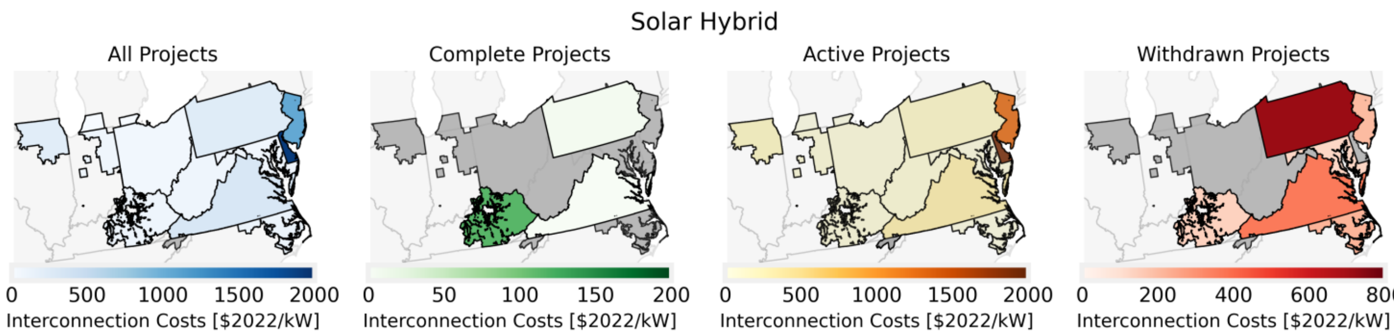

Figure 20 Interconnection Costs by State and Request Status: Solar Hybrid *(means, 2017-2022, grey areas indicate no data)*

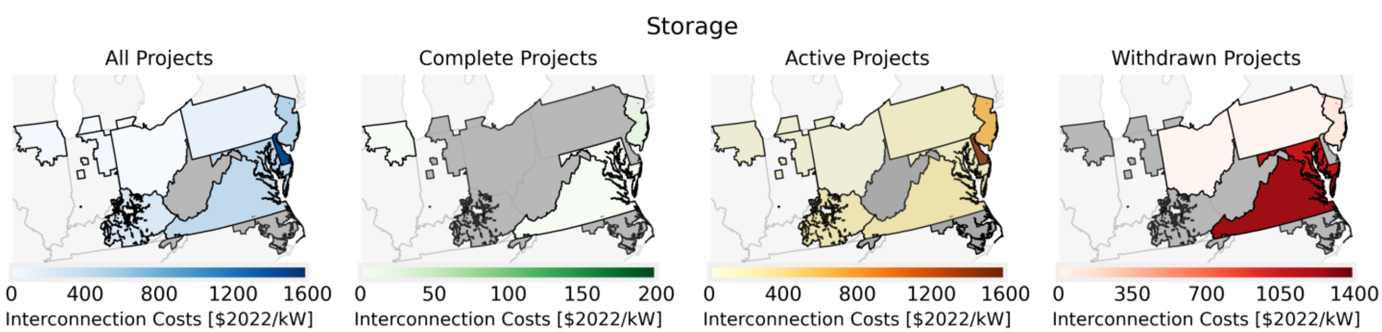

Figure 21 Interconnection Costs by State and Request Status: Storage *(means, 2017-2022, grey areas indicate no data)*

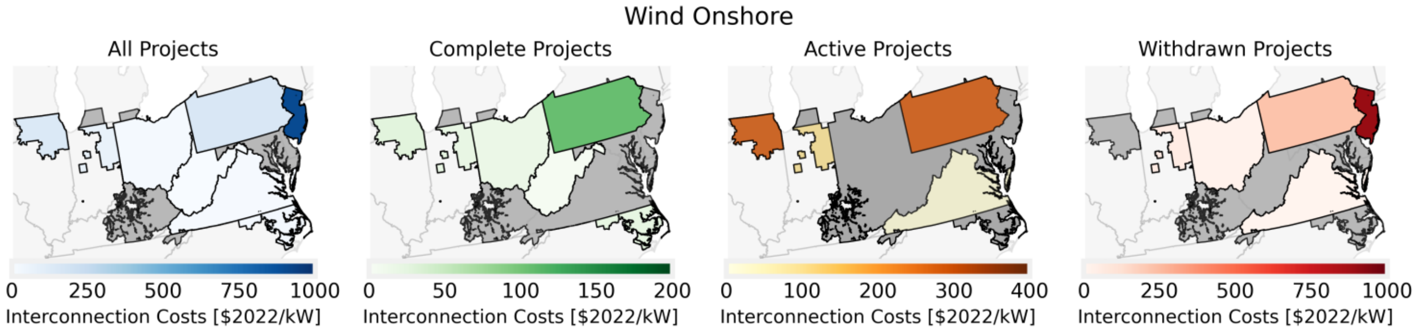

Figure 22 Interconnection Costs by State and Request Status: Wind Onshore *(means, 2017-2022, grey areas indicate no data)*

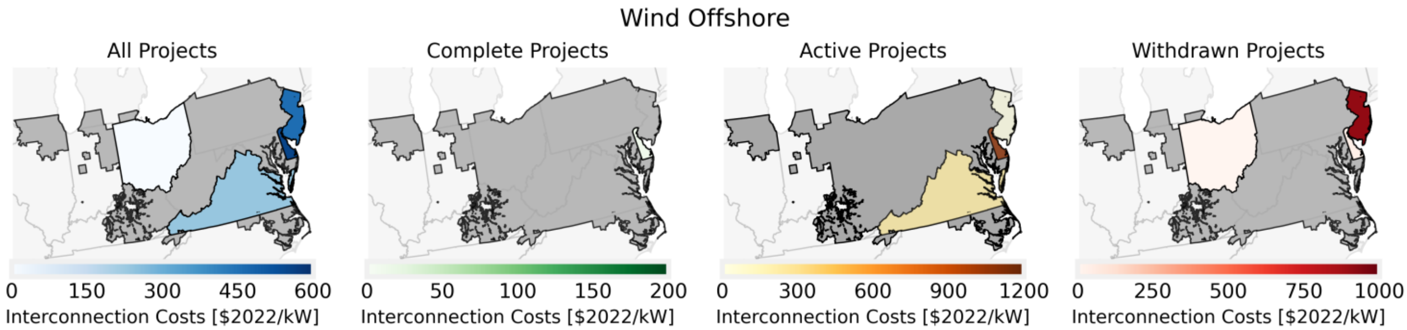

Figure 23 Interconnection Costs by State and Request Status: Wind Offshore *(means, 2017-2022, grey areas indicate no data)*

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gospitznogle@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 13, 2023 10:08:29 -8:00 [9ED63D51C20A] [167.239.221.103]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Gary O. Spitznogle, being duly sworn, deposes and says he is the Vice President of Environmental Services for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Gary O. Spitznogle

Gary O. Spitznogle

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gary O. Spitznogle, on June 13, 2023.

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025

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My Commission Expires 06/21/2025

Notary ID Number KYNP31964

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Brian K. West

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on June 16, 2023.

Marilyn M. Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
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tharatym@crai.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 13, 2023 06:35:32 -8:00 [599EDD091FE2] [167.239.221.104]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Tomasz J. Haratym, being duly sworn, deposes and says he is the Associate Principal, for Charles River Associates, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Tomasz Haratym

Tomasz J. Haratym

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tomasz J. Haratym, on ____June 13, 2023________.

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
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Notary ID Number ____KYNP31964______________

VERIFICATION

The undersigned, Jeffrey R. Huber, being duly sworn, deposes and says he is the Principal, for GDS Associates, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Jeffrey R. Huber

State of Georgia)
County of Bartow)

Case No. 2023-00092

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey R. Huber, on June 13, 2023.

Notary Public

LISA D PARKER
Notary Public, Georgia
Bartow County
My Commission Expires
January 08, 2027

STATE OF NOTARY PUBLIC GEORGIA

My Commission Expires January 8, 2027

Notary ID Number ______________________

Soller Verification Form rev1.doc

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E-Signature Summary

E-Signature 1: Gregory Jerome Soller (GJS)
June 16, 2023 08:36:37 -8:00 [D48C371F47DA] [167.239.221.106]
gsoller@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 16, 2023 08:36:37 -8:00 [84969C7E5A20] [167.239.221.105]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Gregory J. Soller, being duly sworn, deposes and says he is the Resource Planning Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief..

Gregory Jerome Soller

Gregory J. Soller

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory J. Soller, on _____June 16, 2023________.

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025

Notarial act performed by audio-visual communication

My Commission Expires ______06/21/25_____________

Notary ID Number ____KYNP31964________________

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Created: June 14, 2023 04:56:14 -8:00
Pages: 1
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E-Signature Summary

E-Signature 1: Glenn Newman (GN)
June 14, 2023 08:38:19 -8:00 [F27763056967] [167.239.221.105]
rnewman@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 14, 2023 08:38:19 -8:00 [5076D00D8147] [167.239.221.107]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Glenn R. Newman, being duly sworn, deposes and says he is the Manager of Economic Forecasting for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Glenn Newman

Glenn R. Newman

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Glenn R. Newman, on June 14, 2023.

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025

Notarial act performed by audio-visual communication

My Commission Expires 06/21/2025

Notary ID Number KYNP31964