COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF KENTUCKY POWER COMPANY FOR APPROVAL OF A SPECIAL CONTRACT WITH EBON INTERNATIONAL, LLC	))))	CASE NO. 2022-00387

TESTIMONY OF CHELSEA HOTALING

ON BEHALF OF MOVANTS FOR JOINT INTERVENTION MOUNTAIN ASSOCIATION, KENTUCKIANS FOR THE COMMONWEALTH, APPALACHIAN CITIZENS' LAW CENTER, SIERRA CLUB, AND KENTUCKY RESOURCES COUNCIL, INC.

PUBLIC VERSION

February 8, 2023

TABLE OF CONTENTS

I. Introductions & Qualifications

Q. Please state for the record your name and business address.

A. My name is Chelsea Hotaling. My business address is 30 Court Street, Canton, NY 13617.

Q. By whom are you employed and in what position?

A. I am a Consultant at Energy Futures Group ("EFG"), a consulting firm that provides specialized expertise on energy efficiency and renewable energy markets, program design, power system planning, and energy policy.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens Law Center, Sierra Club, and Kentucky Resources Council (collectively ("Joint Intervenors").

Q. Please describe your educational background.

A. I received a Bachelor's Degree in Accounting and Economics from Elmira College in 2011. I also received a Master's in Business Administration in 2012, a Master's in Data Analytics in 2020, and a Master's in Environmental Policy in 2019, from Clarkson University.

Q. Please describe your professional background.

A. I have worked for seven years in electric utility regulation and related fields. I have reviewed over a dozen integrated resource plans (IRPs) and related filings by utilities located in Arizona, Colorado, Kansas, Kentucky, Iowa, Indiana, Michigan, Missouri, Montana, Minnesota, New Mexico, Nova Scotia, Puerto Rico, and South Carolina. I have performed my own capacity expansion and production cost modeling in numerous cases, and I have reviewed planning modeling based on multiple models including EnCompass, Aurora, PLEXOS, PowerSimm, and System Optimizer. A copy of my curriculum vitae is attached as Appendix A.

Q: Have you previously filed expert witness testimony in other proceedings before this Commission or before other regulatory commissions?

A: I have filed testimony before the Kentucky Public Service Commission ("Commission") in Case No. 2022-00371. I have also provided expert testimony to the Colorado Public Utilities Commission, the Michigan Public Service Commission, and the Iowa Utilities Board.

Q. What is the purpose of your testimony?

A. EFG was retained by the Joint Intervenors to assist in the evaluation of the Special Contract for Firm Electric Service between Kentucky Power Company ("KPCO" or the "Company") and Ebon International, LLC ("Ebon") that was filed with the Commission on October 28, 2022. The purpose of my testimony is to provide my evaluation of KPCO's capacity position and the marginal cost of service calculated by KPCO in support of its filing.

II. Summary of Recommendations

Q. Please summarize the request in this proceeding.

A. KPCO is requesting approval of the Special Contract between KPCO and Ebon International, LLC. Ebon has proposed to develop, finance, construct, and operate a blockchain data computing complex on a portion of the site at the Company's Big Sandy

Generating Station. The contract capacity for Ebon is planned to be 80 MW[1] in Phase One (year one of contract) and 250 MW in Phase Two (years two through ten of contract). KPCO has reported that Ebon cannot take service under Tariff Economic Development Rider ("EDR") since Ebon's Total Capacity Reservation is greater than the current MW cap for Tariff EDR (approximately 211 MW is unsubscribed[2]) and that Ebon required a more complex billing calculation. The Special Contract is for Ebon to receive service under the Industrial General Service tariff with a special rate design, which allows Ebon to receive discounts related to economic development. While Ebon would receive economic development discounts under the contract, it is not being offered under the Economic Development Rider ("EDR").

Q. Please summarize your findings and recommendations in this case.

A. Based upon my review of the evidence in this case, the Integrated Resource Plan ("IRP") stakeholder workshop presentations, and the direct testimony provided by Witness Sherwood, I recommend that the Commission deny the Special Contract as proposed by KPCO.

Q. How is the remainder of your testimony organized?

A. In the remainder of my testimony, I discuss aspects of KPCO's capacity and load position, the upcoming IRP filing, the marginal cost of service analysis, the Floor Price adjustment, additional items for the Commission to consider, and my recommendations.

---

[1] Mr. West's testimony (page 6) referred to the capacity being 80 MW to 100 MW in Phase One. Based on the information KPCO provided in response to AG-KIUC Data Request 1_1 subpart d and supporting workbooks provided by KPCO, it appears that the Phase One capacity will be 80 MW.

[2] Witness West Testimony, page 11.

III. KPCO's Capacity and Load Position

Q. What is KPCO's capacity position after the expiration of the Rockport Unit Power Agreement ("UPA")?

A. Witness West states in his testimony that KPCO will not have sufficient capacity to serve its existing customers once the Rockport UPA expires and that KPCO will need to acquire capacity. Witness West states that the capacity needed to serve its customers will be obtained through the Power Coordination Bridge Agreement ("Bridge PCA") between KPCO and the AEP Operating Companies. Table 1 outlines the actual and forecasted market capacity purchases for KPCO according to the information provided through discovery. It is my understanding that the Power Coordination Bridge Agreement includes PJM Planning Years 2022/2023 and 2023/2024.[3]

Table 1. KPCO Capacity Purchases[4]

PJM Planning Year	Capacity Purchase (MW)	Price ($/MW-day)	Actual/Forecasted[5]
2022/2023	152.4	$50	Actual
2023/2024	70.2	$34.13	Actual
2024/2025[6]	80	$54	Actual
2025/2026[7]	57.6		Forecasted
2026/2027	59		Forecasted
2027/2028	102		Forecasted

[3] KPCO's response to Joint Intervenors Data Request 1_20 subpart b.
[4] Witness West Testimony, page 7.
[5] KPCO's response to Joint Intervenors Data Request 2_6 subpart d.
[6] KPCO's response to Staff Data Request 1_6 where the Company indicates that there will be an 80 MW bilateral market capacity purchase.
[7] Capacity purchase numbers for PJM Planning Year 2025/2026, 2026/2027, and 2027/2028 from KPCO_R_KPSC_1_4_Attachment3.

Q. What capacity position is KPCO projecting throughout Ebon's contract period?

A. With an increase in load and the Company's available generating capacity, there continues to be a need for market purchases and new generation throughout the contract period. KPCO is in the midst of developing its 2022 IRP and has reported that the IRP will be released before March 20, 2023. Figure 1 below shows the starting capacity position for KPCO that was included in the IRP stakeholder workshop held on January 25, 2023.

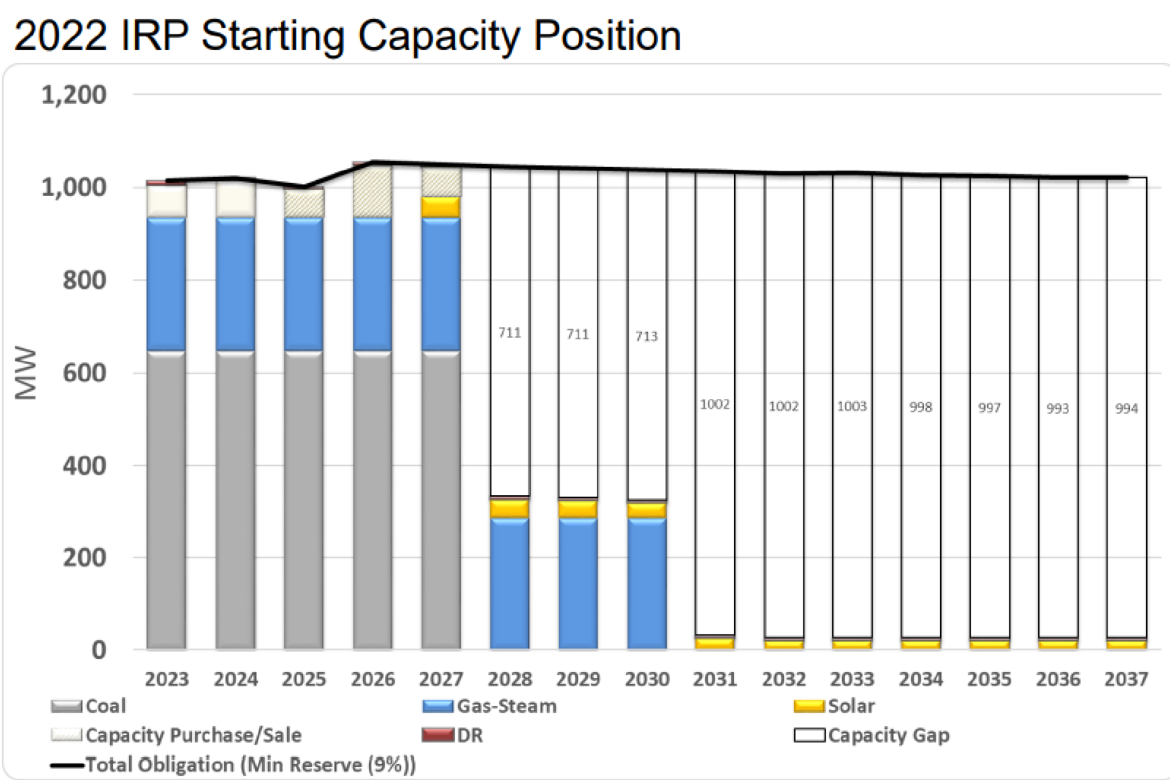


Figure 1. KPCO 2022 IRP Starting Capacity Position (MW)[8]

[8] KPCO 2022 IRP Stakeholder Meeting Material. January 25, 2023. Slide 15.

Q. What is the Total Capacity Reservation for Ebon?

A. Phase One (year one) of the contract is for 80 MW and Phase Two (years two through ten) is for 250 MW. Ebon designated 10 percent of its Total Capacity Reservation as Firm Capacity and the remaining 90 percent is interruptible under Rider Demand Response Service ("D.R.S."). During an event under Rider D.R.S., Ebon would interrupt its operations and shed about 90 percent of its load.[9] For Phase Two of the contract, KPCO would need to acquire 25 MW to meet the PJM capacity requirements. Ebon's annual energy requirements will be 630,720 MWHs for Phase One and 1,971,000 MWHs for Phase Two.[10]

Q. Is it clear how KPCO evaluated the impact that the additional load from Ebon would have on resource planning?

A. No, it is not. KPCO provided three different load forecasts through discovery, as outlined in Table 2 below. KPCO indicated that one forecast was developed to determine the Company's capacity obligation (column b), another forecast is based on the most recent update from PJM[11] (column c), and then the third forecast is KPCO's latest Company forecast[12] (column d). It is my understanding that KPCO's latest forecast as shown in column d of Table 2 below includes the addition of the Ebon load. For the forecast in column c in Table 2 below, in response to a Data Request, KPCO stated that "[n]o load additions for Ebon have provided to PJM. Therefore, the forecasts for Kentucky Power for

---

[9] Witness West Testimony, page 10.

[10] 80 MW x 90% load factor x 8760 hours and 250 MW x 90% load factor x 8760 hours.

[11] In response to Staff's Data Request 2_4 subpart b KPCO stated, "[t]he load obligation information provided in Exhibit 3 is based on the most-recently provided update from PJM. It reflects the most current data available."

[12] In response to Staff's Data Request 2_4 subpart a, KPCO stated, "[t]he forecast included as Attachment 2 is the Company's latest forecast. This forecast was developed after the modeling process for determining the Company's capacity obligation was initiated."

PJM planning purposes do not include Ebon. The capacity obligation would not change specifically for Ebon until the year after Ebon is operational."[13] When asked about the pattern of the load forecast as shown in column c of Table 2 below, the Company said the increase was due to "[t]he transition from using PJM planning parameters through DY 26/27 to using the Company's forecast coincident with the PJM summer peak beginning DY 27/28. The Company's forecast peak for DY 27/28 and beyond includes Ebon."[14]

Table 2. Comparison of Load Forecasts and Available Capacity

	Peak Demand Forecasts (MW)			**Generation (MW)[15]**	
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**
Year	**Determining Capacity Obligation[16]**	**Most Recent Update from PJM[17]**	**KPCO's Latest Forecast[18]**	**Existing Capacity[19]**	**Market Purchases[20]**
2023	952	1,014	1,011	954	70[21]
2024	1,033	1,015	1,092	938	80[22]
2025	1,030	1,020	1,089	938	58*
2026	1,010	1,002	1,069	938	59*
2027	1,006	1,004	1,065	938	101*
2028	1,000	1,046	1,059	286[23]	-

**Projected purchases included in "KPCO_R_KPSC_1_4_Attachment3*

[13] KPCO's response to AG-KIUC 1_4.
[14] KPCO's response to Joint Intervenors Data Request 2_6 subpart d.
[15] Includes Big Sandy 1, Mitchell 1, Mitchell 2, Demand Response, and short term market purchases.
[16] Forecast from KPCO_R_KPSC_1_4_PublicAttachment1
[17] Forecast from KPCO_R_KPSC_1_4_Attachment3
[18] Forecast from KPCO_R_PSC_1_4_Attachment2
[19] Generating capacity from KPCO_R_KPSC_1_4_Attachment3
[20] Market Purchases from KPCO_R_KPSC_1_4_Attachment3
[21] KPCO's response to Joint Intervenors Data Request 2_6 subpart d.ii and iii indicates that DY 23/24 is pending finalization.
[22] KPCO's response to Joint Intervenors Data Request 2_6 subpart d.ii and iii indicates that DY 24/25 is confirmed.
[23] Mitchell 1 and 2 are no longer included in the generation mix.

Q. Is KPCO including the Ebon load in its modeling for the 2022 IRP Filing?

A. It is not clear whether KPCO is including Ebon's load in the modeling for the Company's 2022 IRP. The 2022 IRP Starting Capacity position shown Figure 1 does appear to be consistent with the load obligation given in Column (d) of Table 2, which is KPCO's most recent load forecast that purports to include Ebon. It is unclear if KPCO's load forecast for the IRP planning purposes includes the additional load from Ebon across all scenarios KPCO is modeling or if it may be modeled as a load sensitivity. When asked if the Company had performed any IRP or long-term planning analyses reflecting the addition of the Ebon load, the Company stated:

> *The Company has not performed any long-term planning analyses that reflect the addition of the Ebon load. However, the requested analysis will be included in the Company next Integrated Resource Plan to be filed on or before March 20, 2023.*[24]

However, the Company also stated:

> *Please see KPCO_R_KPSC_1_4_PublicAttachment1 for the requested information. The load and energy forecast includes assumptions for Ebon load additions. This is the latest forecast, but this forecast will not be included in the Company's next IRP as modeling had already began prior to the creation of this forecast.*[25]

This was in response to the Joint Intervenors' Data Request, which asked:

> *Please refer to the Company's response to the Attorney General 1_21 Data Request, where the Company states, "The Company has not performed any long-term planning analyses that reflect the addition of the Ebon load. However, the requested analysis will be included in the Company next Integrated Resource Plan to be filed on or before March 20, 2023. Please explain how the Company will analyze the Ebon load in the IRP filing.*[26]

[24] KPCO's response to AG-KIUC Data Request 1_21.
[25] KPCO's response to AG-KIUC Data Request 1_29 subpart a.
[26] Joint Intervenors Data Request JI 2_16 to KPCO.

When asked about how the Company would analyze the Ebon load in the IRP filing, the Company stated:

> *The Company cannot meaningfully respond to this request at this time, as the IRP analysis is still being performed. The Company's IRP analysis does not consider specific customer loads. Instead it considers load in the aggregate. The Ebon load will be included in the overall analysis in the Company's IRP filing, due on or before March 20, 2023, the same as all other load additions.*[27]

This response was provided to Joint Intervenors on January 17, 2023, and KPCO will be filing its IRP on March 20, 2023.

Q. Why is it important to know if KPCO has conducted any analysis to evaluate the addition of the Ebon load for planning purposes?

A. Even though Ebon would not be subject directly to the EDR Tariff, the Special Contract allows for Ebon to receive the EDR Tariff discounts. The language of the EDR Tariff states that "(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount."[28] If KPCO wants Ebon to receive the discounts afforded under the terms of the EDR Tariff then it is appropriate for them to be subject to the terms of the Tariff, as discussed in Witness Sherwood's testimony.

In discovery, KPCO stated that "The ultimate mix of resources will be determined in the Company's Integrated Resource Plan ("IRP") to be filed on or before March 20, 2023. In general, the mix of resources includes solar, wind and natural gas added at various levels and years, as needed."[29] This statement highlights the importance of knowing what

[27] KPCO's response to Joint Intervenors Data Request 2_16.
[28] KPCO Company Tariff E.D.R. Sheet No. 37-1. Retrieved from https://psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Tariff.pdf
[29] KPCO's response to Staff 's Data Request 1_5.

resource mix is determined from the IRP and whether or not the addition of the Ebon load would impact the timing of generating capacity.

Figure 2 shows the Reference Portfolio Capacity Balance that was presented in the IRP stakeholder workshop held on January 25, 2023. This figure indicates that there will be market capacity purchases as well as potentially generation resources within the time frame of the contract. I will note that I am not certain if Figure 2 incorporates the addition of the Ebon load. The projected capacity position seems to suggest an increase in load between 2025 and 2026 that may reflect Ebon, but I cannot be certain without more information about the load forecast that is shown in Figure 2.

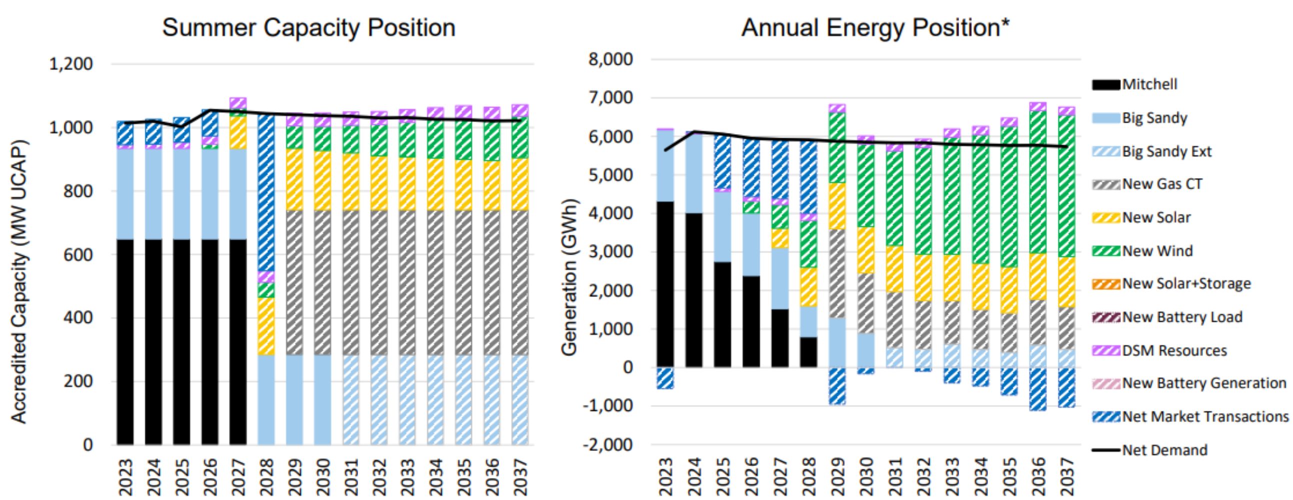


Figure 2. Reference Portfolio Capacity Balance[30]

[30] KPCO 2022 IRP Stakeholder Meeting Material. January 25, 2023. Slide 45, attached as Appendix B.

IV. Ebon's Participation in Rider D.R.S.

Q. How does KPCO manage Rider D.R.S.?

A. For customers enrolled in the D.R.S. Tariff, KPCO will interrupt customers so that the interruptible load is not included in the summer peak load reported to PJM for purposes of establishing the Fixed Resource Requirement ("FRR") capacity obligation.[31]

Q. Has KPCO claimed that there would be a benefit for all customers with Ebon's participation in Rider D.R.S.?

A. Yes, Witness West states that "[f]inally, by agreeing to drop 90 percent of its load when called upon to do so, Ebon will be helping the Company to shave its coincident peaks in PJM and avoid the need for additional capacity, a cost savings that would be passed on to all customers."[32] It's not clear how the Company could arrive at this conclusion. Any additional firm load added to the Company's system will increase the overall Company load obligation and those additional costs would seemingly be passed to all customers. That those costs would correspond to an increase in capacity obligation that is 10% of Ebon's load, rather than 100% is not a cost savings, but merely a smaller magnitude of additional cost.

Q. Are there risks to customers if Ebon does not interrupt its load?

A. Under Rider D.R.S., there are seven allowances for failure of curtailment. In its response to AG-KIUC's Data Request, KPCO indicated that "[t]he current Commission-approved Rider D.R.S. provides for payback of the discount achieved under the rider by the

---

[31] KPCO's response to AG-KIUC Data Request 1_16, 1_22, and 2_19.
[32] Witness West Testimony, page 9.

participating customer if they were to fail to curtail."[33] This language seems to indicate that there would be a mechanism for Ebon to have to pay back the discount for Rider D.R.S., but it does not account for the implications that failure to curtail can have on KPCO's PJM obligations for the following year.

Staff asked KPCO about the consequences of Ebon failing to reduce its load to 25 MW if called upon to do so under Rider D.R.S. KPCO stated that "If Ebon were to not fully interrupt during the 5CP hours the Company would have to account for that additional capacity obligation (assuming all other loads/things equal) in the subsequent delivery year."[34]

Staff also asked KPCO about the cost if Ebon did not reduce its load to 25 MW during one of the PJM 5 CP hours. In its response, the Company stated:

> There are simply too many external factors to provide a meaningful response to this hypothetical. However, generally, from a load obligation perspective each MW above its firm service level that a Rider DRS customer fails to curtail would add .2 MWs of additional load obligation in a future delivery year.[35]

If KPCO's response is correct, this would mean that if Ebon does not curtail its load, then KPCO could face an additional load obligation of 45 MW (225 MW x .2 MW) in future years.

[33] KPCO's response to AG-KIUC Data Request 1_23.
[34] KPCO's response to Staff Data Request 2_12.
[35] KPCO's response to AG-KIUC Data Request 2_16.

V. Marginal Cost of Service for Generation Capacity

Q. How did KPCO treat generation capacity costs in the marginal cost analysis?

A KPCO did not include generation capacity costs in the marginal cost analysis for Ebon. In his testimony, Witness West states that "[t]he Company will not incur any additional incremental costs to purchase capacity otherwise provided by Rockport through at least May 31, 2024."[36]

Based on information provided by KPCO, it appears the assumption is that additional short-term market capacity purchases will be needed to bridge the gap between the Company's load and available generating capacity. It is not clear how any incremental capacity market purchases attributed to the load from Ebon will be treated. In response to Staff's discovery request on whether the charges under the Tariff Purchase Power Adjustment will equal capacity purchase costs, the Company stated:

> *The proposed Special Contract is based upon the otherwise applicable Tariff IGS rates, inclusive of the Purchased Power Adjustment (PPA). There is no guarantee that the tariff based charges under Tariff PPA would exactly equal an attributable marginal cost of generation capacity.*[37]

VI. Contract Floor Price Adjustment

[redacted]

[36] Witness West Testimony, page 8.
[37] KPCO's response to Staff Data Request 2_6.
[38] [redacted].

[redacted]

Q. Has KPCO explained how the Floor Prices were determined?

A. In response to Staff's Data Request, KPCO stated:

> *When the contract negotiations began, the calculated bill for the Ebon load under Tariffs I.G.S., E.D.R. and D.R.S. produced a realized rate lower than the Company's estimate of the marginal cost to serve. The floor price mechanism was put in place to raise the realized rate to more acceptable (still negotiated) levels over the 10-year contract. It also provides a mechanism to keep the special contract customer's rates lower over time by banking credits for periods where energy costs are low and realized rates are lower than the floor price for time periods when the reverse is true.*[40]

KPCO provides no evidence showing how the Floor Price was established since it was a negotiated rate.

[redacted]

---

[39] [redacted]

[40] KPCO's response to Staff Data Request 1_11.

[redacted]

[41] [redacted]

[42] [redacted]

[43] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

44 [redacted]

45 [redacted]

46 [redacted]

Q. Do you have any recommendations related to the Floor Price Bank?

A. Yes. First, the balance of the Floor Price Bank should be limited to the first five years of the contract term, if not zeroed out annually, so that this pricing mechanism does not allow Ebon to "bank" EDR discounts and use them beyond the first five years of the contract. Second, while its understandable that the negotiated rate between Ebon and KPCO should not be made public, the assumptions behind the rate and proof that the Floor Price is sufficient to cover the costs to bring Ebon on to KPCO's system and provide service is sufficiently met should be provided by KPCO in this proceeding for review and approval by the Commission.

VII. Additional Items for Consideration

Q. Are there other items that the Commission should consider for the Ebon Special Contract?

A. Yes, I believe there are two other items that should be considered for the Ebon Special Contract, and they include the opportunity cost of new generation that could be sited at the Big Sandy site and the potential impact on wholesale energy market prices from the 250 MW addition of the Ebon load.

Opportunity Cost for Big Sandy Generating Site

The Ebon facility will be located at the Company's Big Sandy Generating Station site. It is possible that the location of Ebon and its permanent infrastructure at the Big Sandy Generating Station site will preclude KPCO from pursuing opportunities to site new generation facilities at the site. This has implications for any other projects that might otherwise be developed at the Big Sandy site, particularly in light of the Inflation Reduction

Act's ("IRA") 10% bonus to tax credits[47] for development of facilities that are located in energy communities. One of the conditions for qualification as an energy community is a census tract (or adjoining tract) where a coal mine has closed after December 31, 1999 or in which any coal power plant has been retired after December 31, 2009.[48] This means that any potential new generation resources would at least receive the bonus plus the energy communities bonus adder if they could be located at the Big Sandy generation site. Moreover, siting potential new generation resources at the site would take advantage of the transmission infrastructure that already exists at the site (unlike the Ebon facility). Another related impact relative to the Big Sandy site is the decision of whether to extend the existing gas generating unit at the facility beyond 2030. All scenarios except for one presented in the IRP stakeholder workshop showed the operating life of Big Sandy extended after 2030.[49] Again, it is not clear if Ebon was included in the load that was modeled for these scenarios in the IRP, or to what extent the potential addition of the Ebon load (especially given that it is located at the Big Sandy site) might be contributing to the Company's consideration of an extension of the Big Sandy gas unit. Without more details about the modeling, and the final modeling scenarios from the IRP, it is not possible for me to determine if the addition of Ebon's load is having an influence on any decisions to extend the life of the Big Sandy generating facility. However, any such extension of the Big Sandy

---

[47] The bonus applies for projects that qualify for the Investment Tax Credit ("ITC") and the Production Tax Credit ("PTC").

[48] S&P Global. Mapping communities eligible for additional Inflation Reduction Act incentives. Retrieved from https://www.spglobal.com/marketintelligence/en/news-insights/research/mapping-communities-eligible-for-additional-inflation-reduction-act-incentives#:~:text=With%20its%20%22energy%20community%22%20special%20rule%2C%20the%20Inflation,revitalization%20strategy%20on%20top%20of%20energy%20transition%20objectives.

[49] KPCO 2022 IRP Stakeholder Meeting Material. January 25, 2023. Slide 47, attached as Appendix B.

gas unit would have negative effects on local communities, as discussed in Witness Sherwood's testimony.

Ebon Load and Increase Impact on Market Prices

By the end of Phase Two of the contract, Ebon's load is anticipated to be 250 MW, which is a significant increase in the capacity and energy requirements of KPCO's system – a roughly 30%[50] increase in energy requirements. One potential impact from this new load would be an increase in the wholesale market prices experienced by all of KPCO's load and passed onto all customers. The reverse of this impact – a price decrease in response to demand reduction – has been observed and documented previously and given the name Demand Reduction Induced Price Effects ("DRIPE"). DRIPE is a benefit of energy efficiency measures implemented in organized wholesale markets. For example, the Avoided Energy Supply Components ("AESC") Report estimates the avoided costs associated with energy efficiency measures in the ISO New England footprint and describes DRIPE as:

> […] the reduction in prices in the wholesale markets for capacity and energy- relative to the prices forecast in the Reference case- resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period."[51]

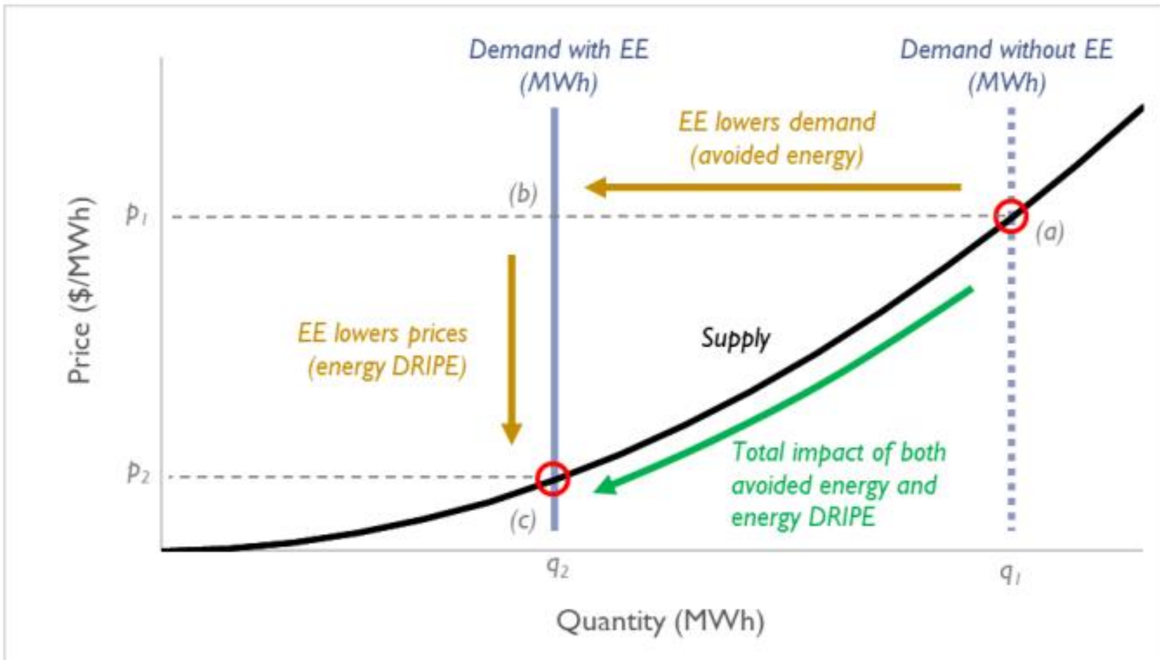
The impact of DRIPE manifests in the downward movement in the electricity demand curve which leads to a lower point on the supply curve. The impact of both the avoided energy and energy DRIPE is depicted in Figure 3 below. Once the demand curve shifts left

---

[50] Ebon's projected annual energy is 1,971,000 (250 MW x 90% load factor x 8760 hours). In KPCO_R_PSC_1_4_Attachment2, KPCO is projecting an annual energy requirement of 6,409,933 MWHs in 2025.

[51] Avoided Energy Supply Components in New England: 2021 Report. Page 193. Retrieved from https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

(movement from dotted blue line to solid blue line) because of the implementation of energy efficiency measures, the result is a downward movement in the supply curve (black curve), which results in a lower price on the curve.



Note: This example figure depicts impacts in the energy market, but the principles are the same for all other DRIPE categories. This figure also uses "EE" as an example measure. DRIPE effects can be calculated for any measure (EE or otherwise), including measures that increase the demand of a commodity.

Figure 3. Depiction of Avoided Energy and DRIPE Effect[52]

I acknowledge that the principle of DRIPE is based on the reduction of demand, which is not the case for the Ebon contract. However, given the magnitude of the Ebon load addition, it seems possible that the opposite would be true, in effect moving from the solid blue line in Figure 3 to the dotted blue line and causing market clearing prices to be higher. For the ISO-NE evaluation in the AESC Report, an intrazonal and an interzonal

[52] Avoided Energy Supply Components in New England: 2021 Report. Figure 46, page 194. Retrieved from https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

DRIPE is calculated. Intra-zonal looks at the load impacts within a zone and inter-zonal looks beyond the borders of the zone.[53] The total DRIPE effect was calculated as the sum of the intrazonal and interzonal values. In the AES report it acknowledges the impact of the DRIPE effect:

> Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms for the state or region. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.[54]

Drawing on the DRIPE impacts from the implementation of energy efficiency measures on market prices, it seems possible that the additional load from Ebon could result in the opposite impact of DRIPE where market prices increase in response to the additional load on the system.

VIII. Recommendation for the Ebon International, LLC Special Contract

Q. What recommendations do you have for the Commission?

A. Based on the anticipated significant deficit of capacity to serve KPCO's current load, much less the additional load from the proposed Ebon facility, as well as the risk of negative impacts on customers from signing this contract, I recommend that the Commission deny the Ebon Special Contract.

[53] Avoided Energy Supply Components in New England: 2021 Report. Page 196. Retrieved from https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.
[54] Avoided Energy Supply Components in New England: 2021 Report. Page 195. Retrieved from https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

In the event that the Ebon Special Contract is approved by the Commission, I would recommend that additional protections and guardrails be put in place in order to prevent an adverse impact to the rest of KPCO's customer base:

(1) If KPCO identifies new generation options to pursue in the IRP, and the load from Ebon was not included in the IRP forecast, then the full incremental cost of any new generation to cover the Ebon load should be assigned to Ebon.

(2) If KPCO pursues market capacity purchases to cover the load from Ebon, then the full cost of those market capacity purchases should be assigned to Ebon.

(3) If Ebon fails to curtail its load when called upon for a Rider D.R.S. event and KPCO needs to acquire capacity to meet its PJM obligation for the following year, then the full cost of that capacity should be assessed to Ebon.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

The undersigned, Chelsea Hotaling, being first duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of her information, knowledge, and belief, after reasonable inquiry.

Chelsea Hotaling

Subscribed and sworn to before me by Chelsea Hotaling this 6th day of Feb., 2023.

Notary Public

My commission expires: 03/16/2026

NOTARY PUBLIC ★ STATE OF TEXAS ★

Jennifer Frazier
Notary Public, State of Texas
Comm. Expires 03-16-2026
Notary ID 131492357

Notarized Online with NotaryLive.com

Appendix A

Chelsea Hotaling
Consultant

Professional Summary

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

Education

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

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

MBA, Concentration in Environmental Management, Clarkson University, 2012

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

Experience

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

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

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

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

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

Selected Projects

- GridLab. Performing capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to present)
- Sierra Club. Performing capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants (2022 to present)

- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice. Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)
- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy. Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs

(April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019).

- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

Publications

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

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

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

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

Expert Testimony

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

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

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

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

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

Appendix B

Kentucky Power 2022 IRP

IRP Stakeholder Meeting Material

January 25th, 2023

KENTUCKY POWER

CRA Charles River Associates

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

Microsoft Teams meeting
Join on your computer, mobile app or room
Click here to join the meeting
Meeting ID: 288 986 975 833
Passcode: Mk2feg
Download Teams | Join on the web
Join with a video conferencing device
953812256@t.plcm.vc
Video Conference ID: 118 809 003 1
Alternate VTC instructions
Or call in (audio only)
+1 614-706-7239,,646860402# United States, Columbus
Phone Conference ID: 646 860 402#
Find a local number | Reset PIN | Learn More

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

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.

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

- 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

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.

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

⇩

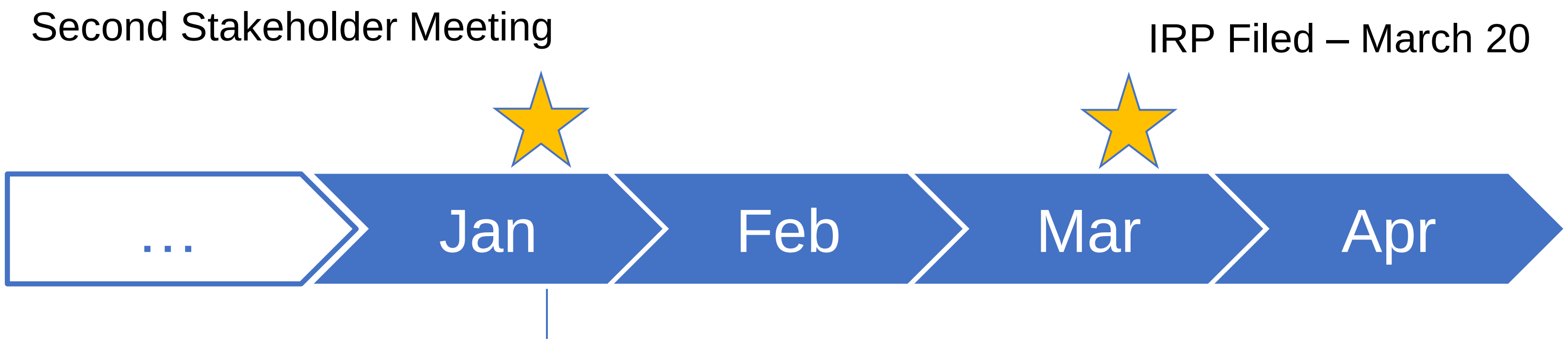
Test Portfolios across Scenarios & Stochastic Risks

⇩

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

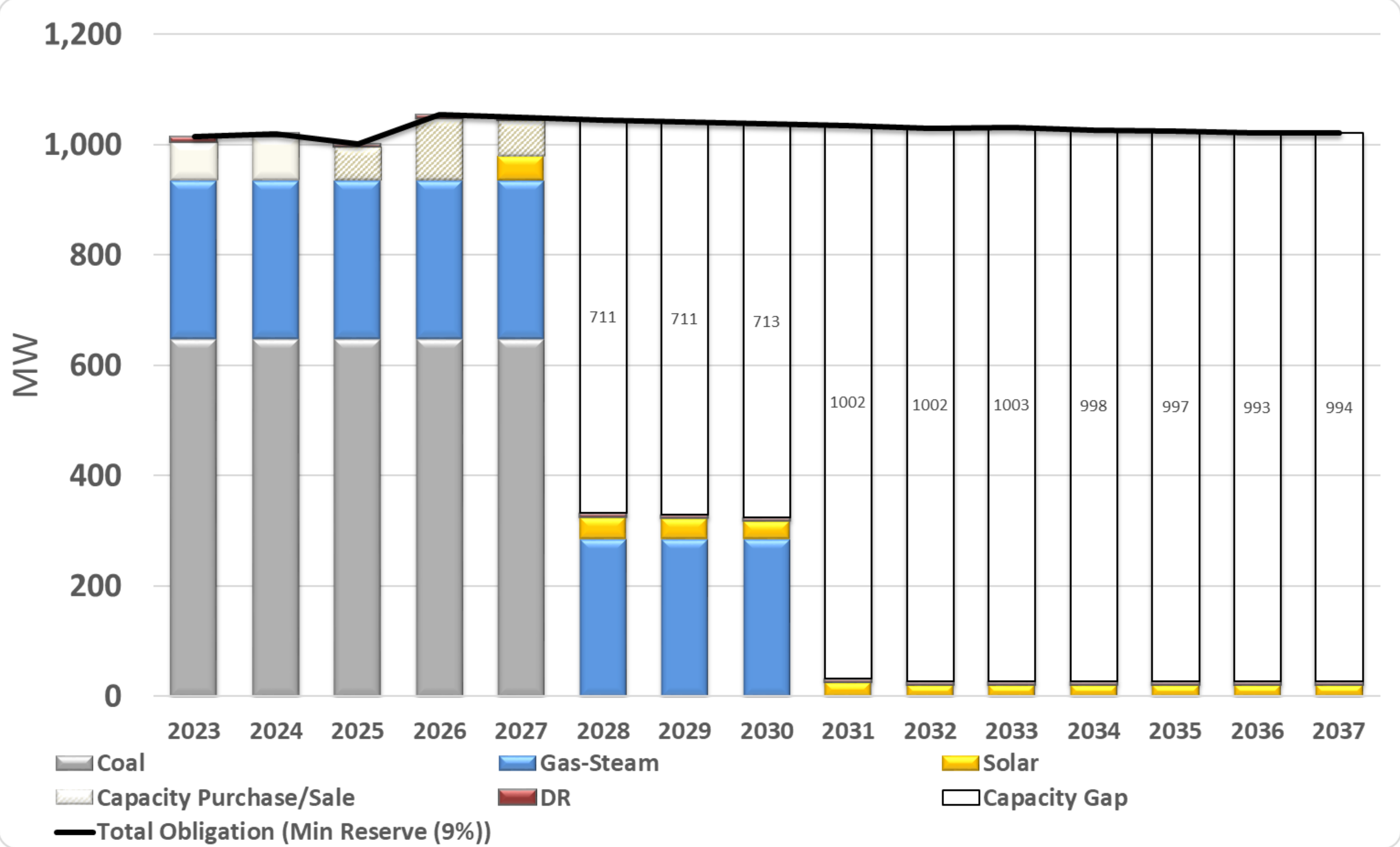
Questions?

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.

2022 IRP Starting Capacity Position



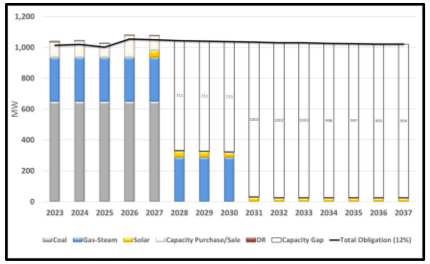
The loss of Mitchell after 2028 and Big Sandy after 2030 leave Kentucky Power with a significant gap after the Rockport UPA expired in 2022

CRA Charles River Associates

KENTUCKY POWER

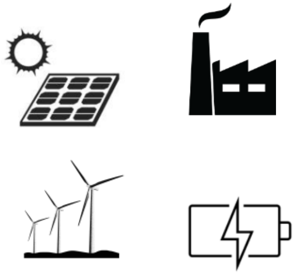
Selection of the Preferred Plan

Going in View



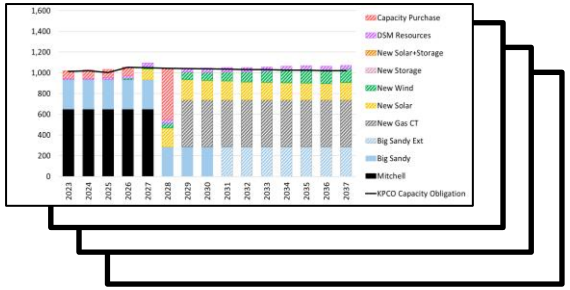
The going in positions shows a need for new capacity to meet Kentucky Power customer requirements

Resource Options

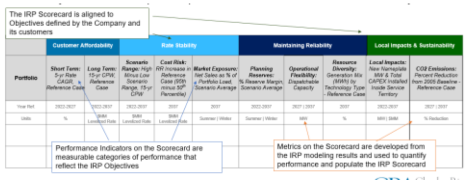


Kentucky Power used AURORA to evaluate resource options under different market conditions and test specific strategies

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.

CRA Charles River Associates

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.

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

KENTUCKY POWER

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

CRA Charles River Associates

KENTUCKY POWER

Questions?

CRA Charles River Associates

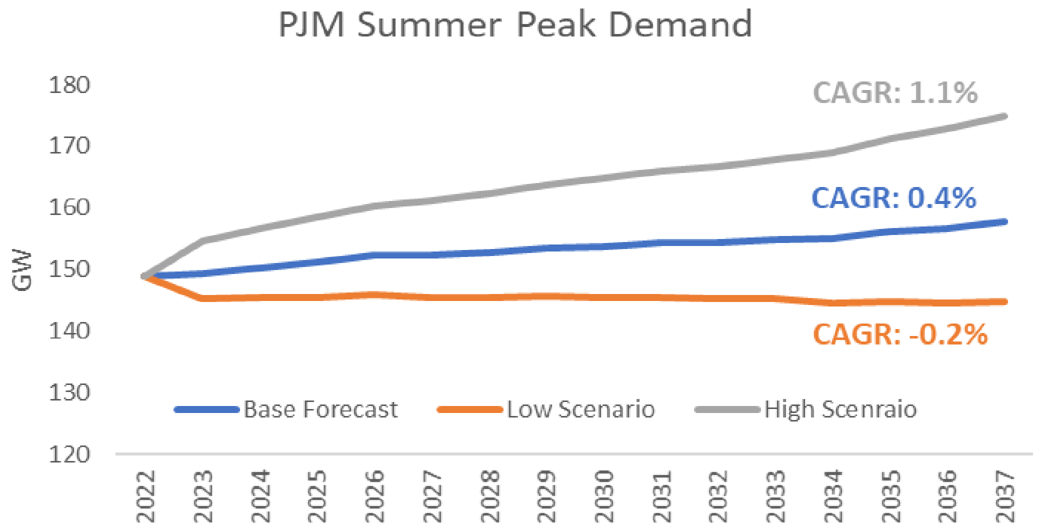
Agenda

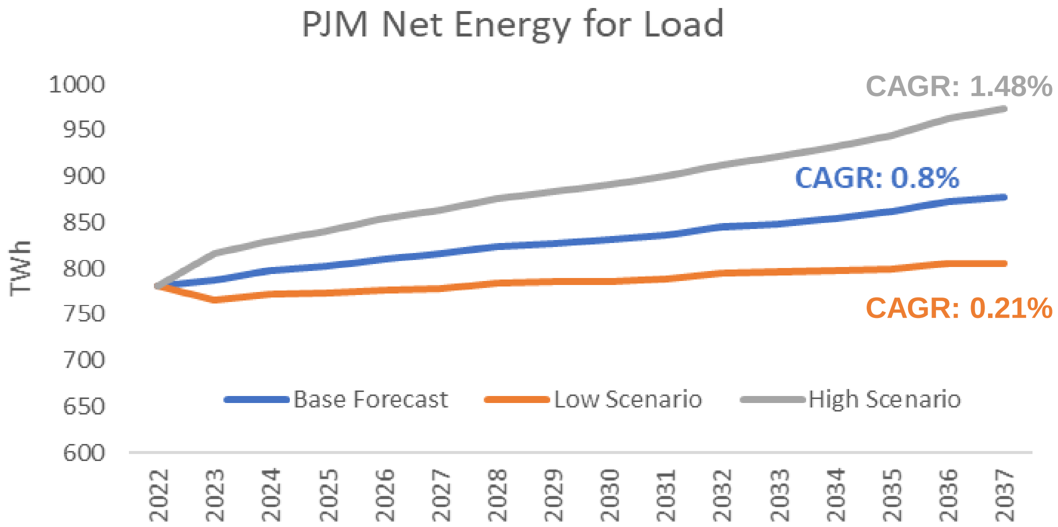
- Welcome and Introductions
- Overview of the 2022 IRP Process
- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
- Market Scenario Results
- Portfolio Development & Results
- Portfolio Risk Analysis
- Scorecard Development
- Discussion & Closing Remarks

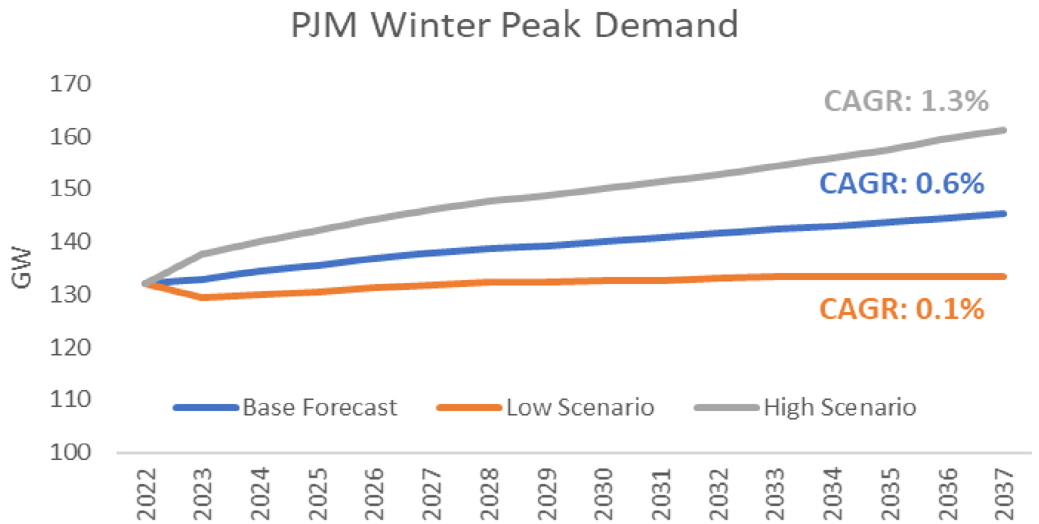
Stakeholder feedback is encouraged throughout the presentation.

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

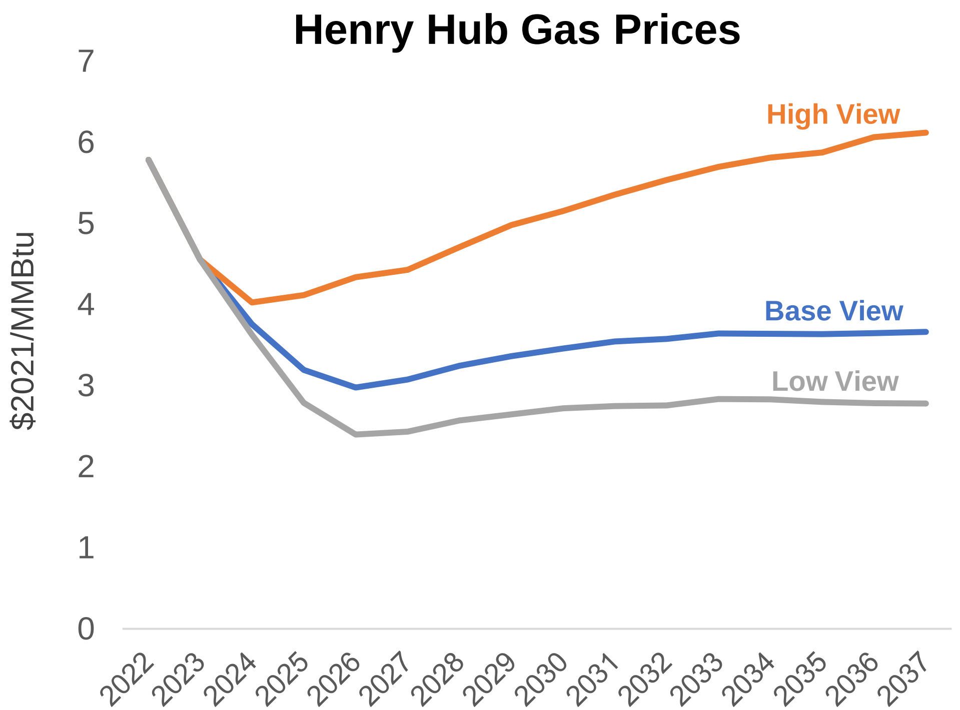


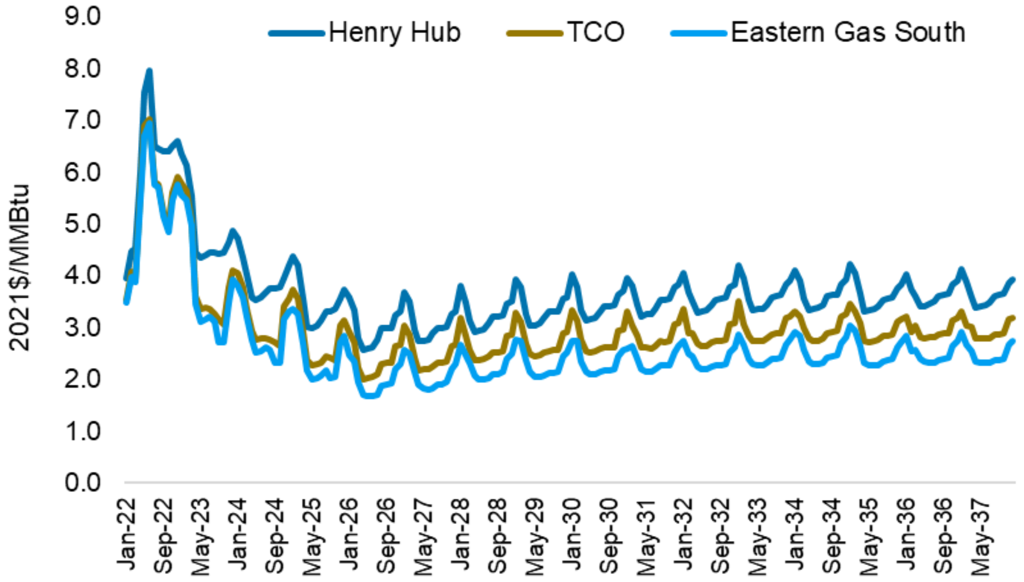




CRA Charles River Associates

Natural Gas Price Ranges



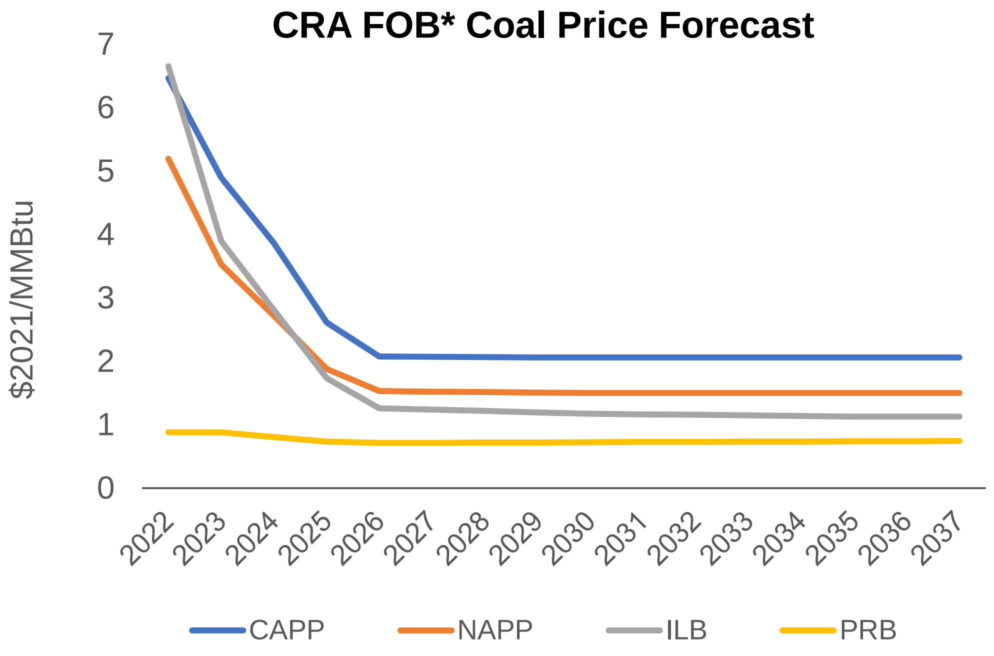


- Kentucky Power sets the range of long-term gas forecasts using EIA's 2022 Annual Energy Outlook forecasts
- Over the first 4 years, recent market data informs expected prices, blend into the AEO views

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

Coal Price Inputs

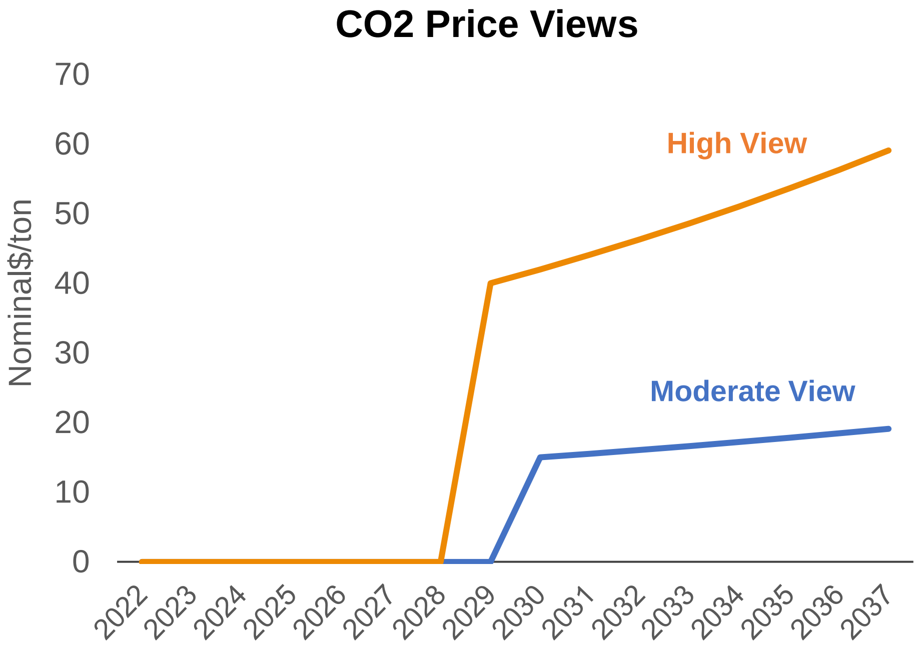
- U.S. coal prices exhibit flat-to-declining trends over the long-term due to continued coal retirement expectations in the US
- Over the long term, U.S. domestic demand for coals is expected to decline significantly, in proportion to the projected declines in U.S. demand for coal-fired generation throughout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

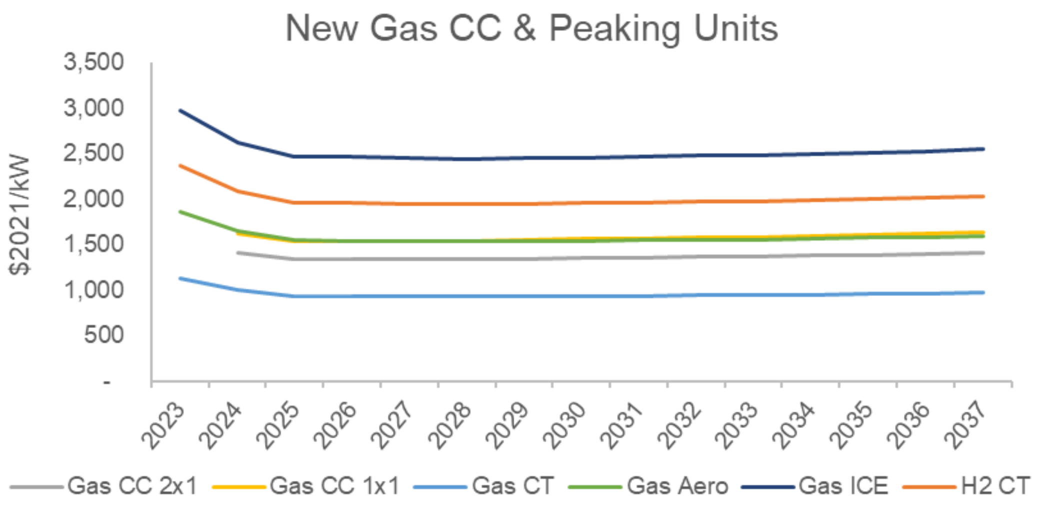
- CO2 prices are assumed to be first implemented in 2030 for the Moderate View and in 2029 for the High View.
- The High view assumes that policymakers take more aggressive action to reduce CO2 emissions over the short term, and trends toward towards the price needed to achieve net-zero reductions in 2050
- The Moderate view reflects the long-term trajectory needed to achieve modest (e.g., 70%) electric-sector emissions reductions by 2050

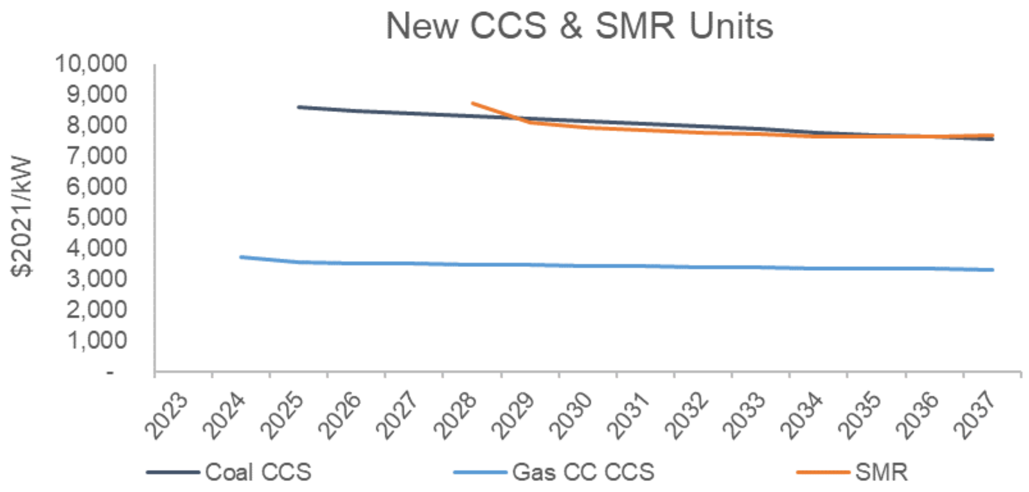


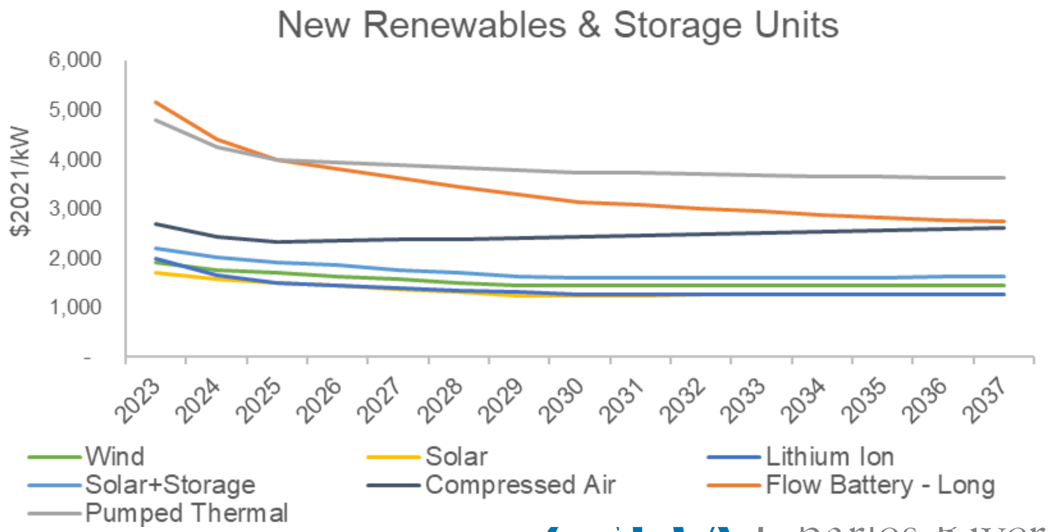
KENTUCKY POWER

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





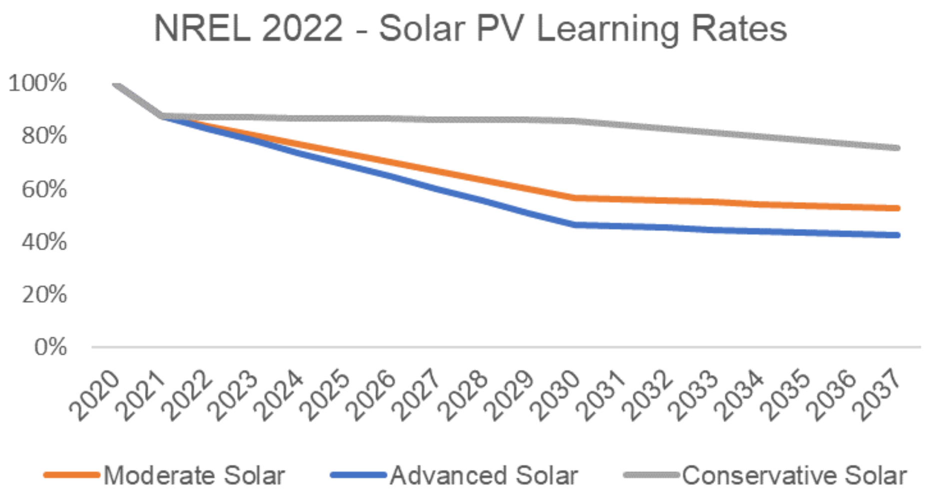


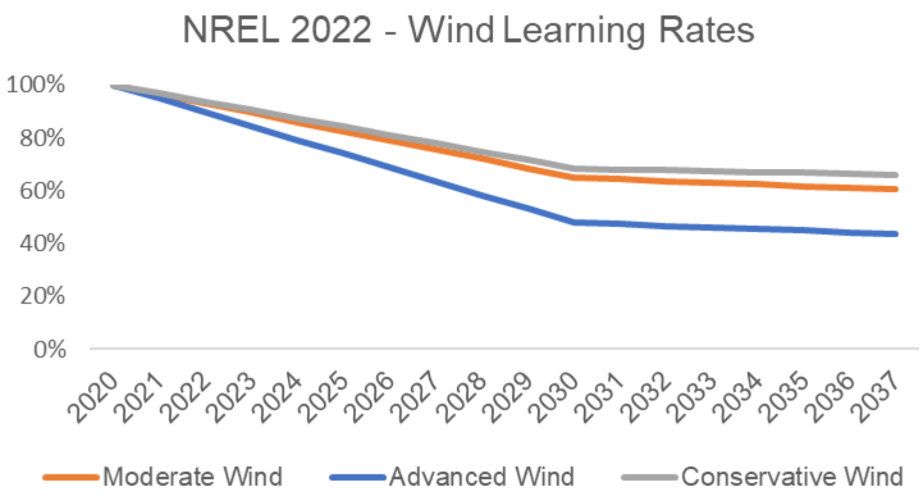
Charles River Associates

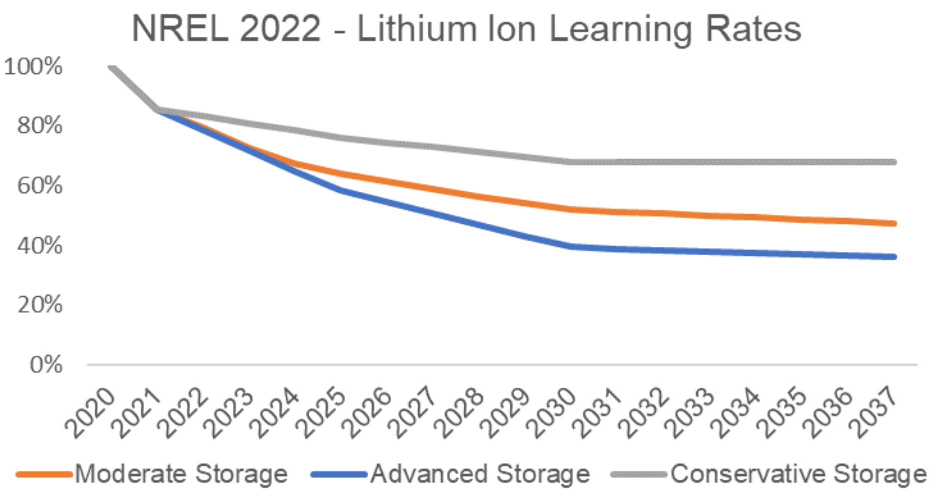
KENTUCKY POWER

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.



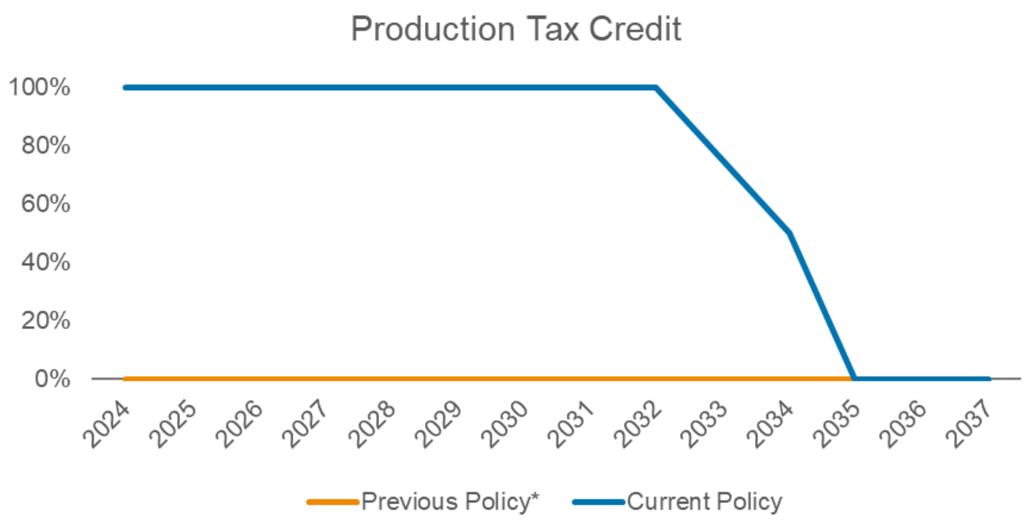


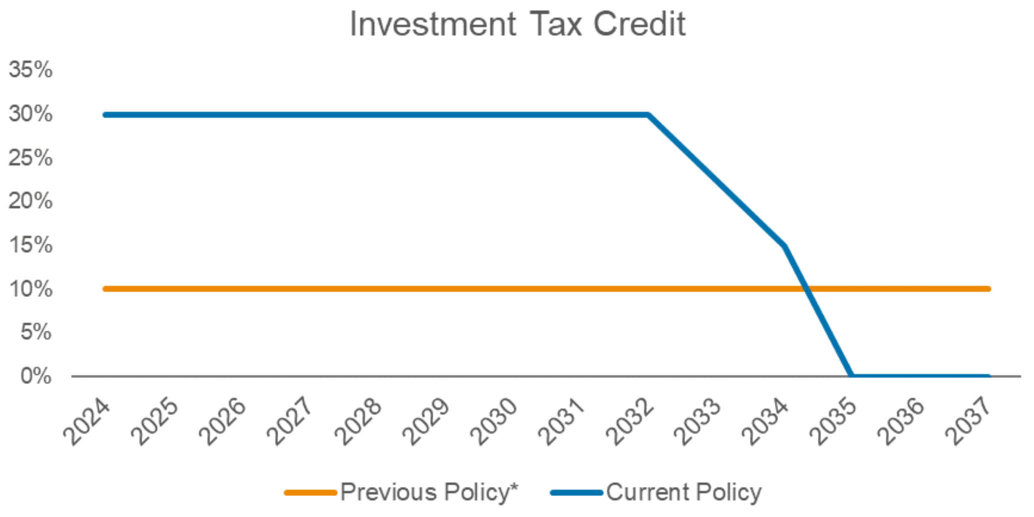


CRA Charles River Associates

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

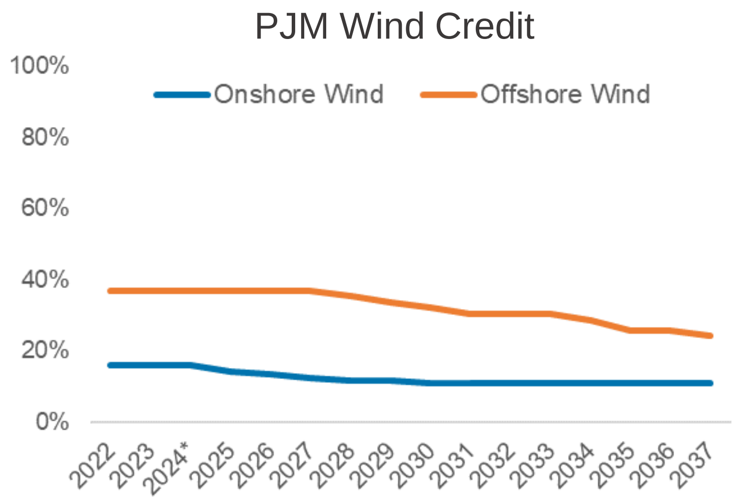
Reserve Requirement and Peak Credit Inputs

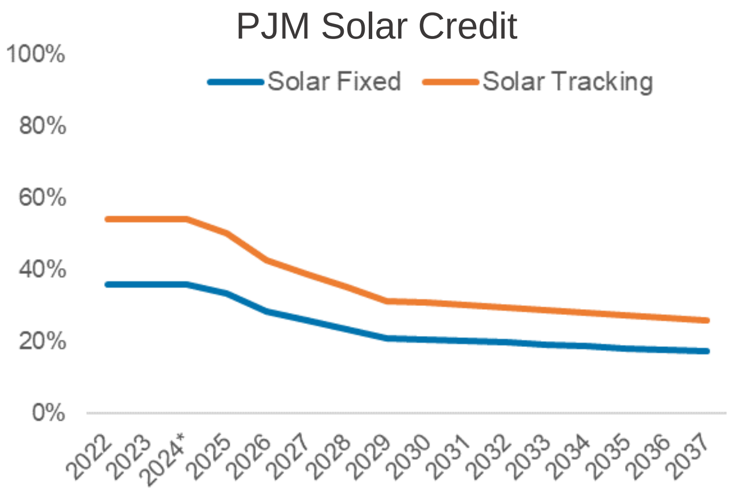
Reserve Requirements

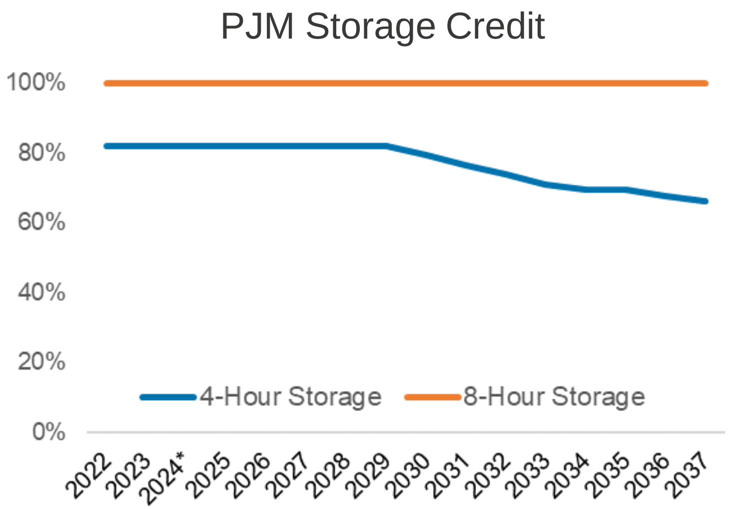
- PJM's Installed Reserve Margin (IRM) target is between 14.7-14.9% above summer peak load for the upcoming planning years. CRA modeled this requirement as a firm constraint on the PJM market model for the LTCE runs.

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.*

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.

KENTUCKY POWER

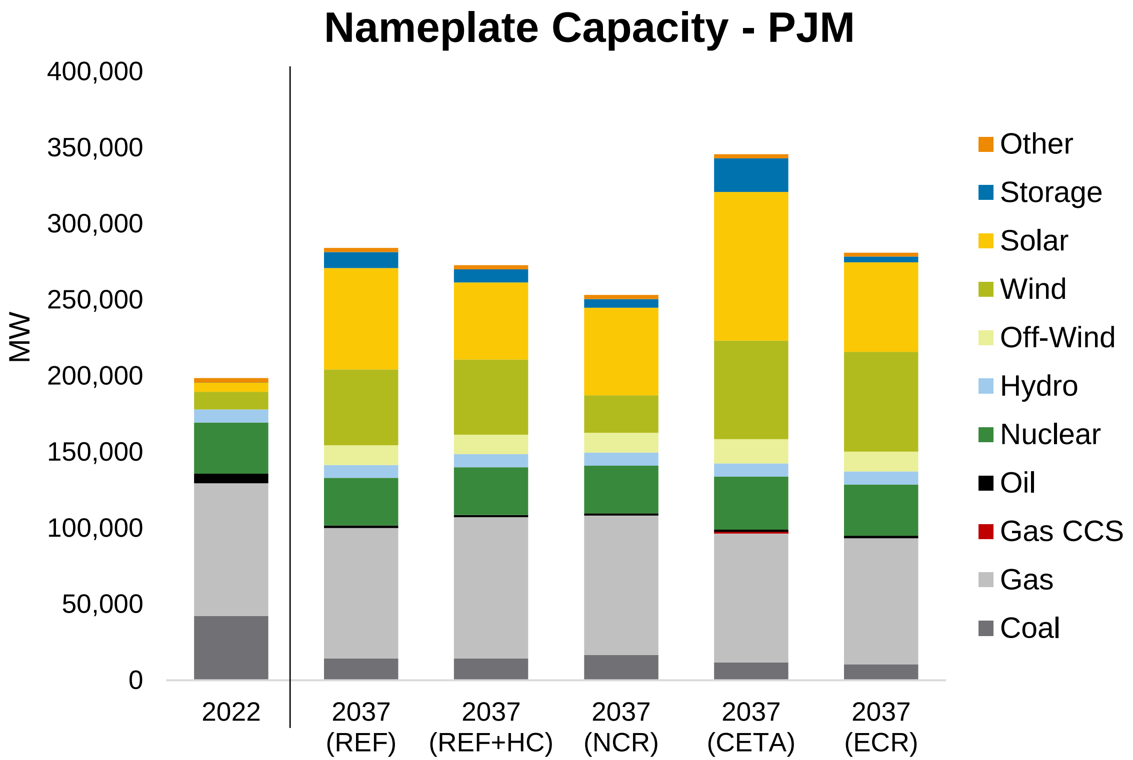
The PJM Market Scenarios Combine Multiple Fundamental Elements

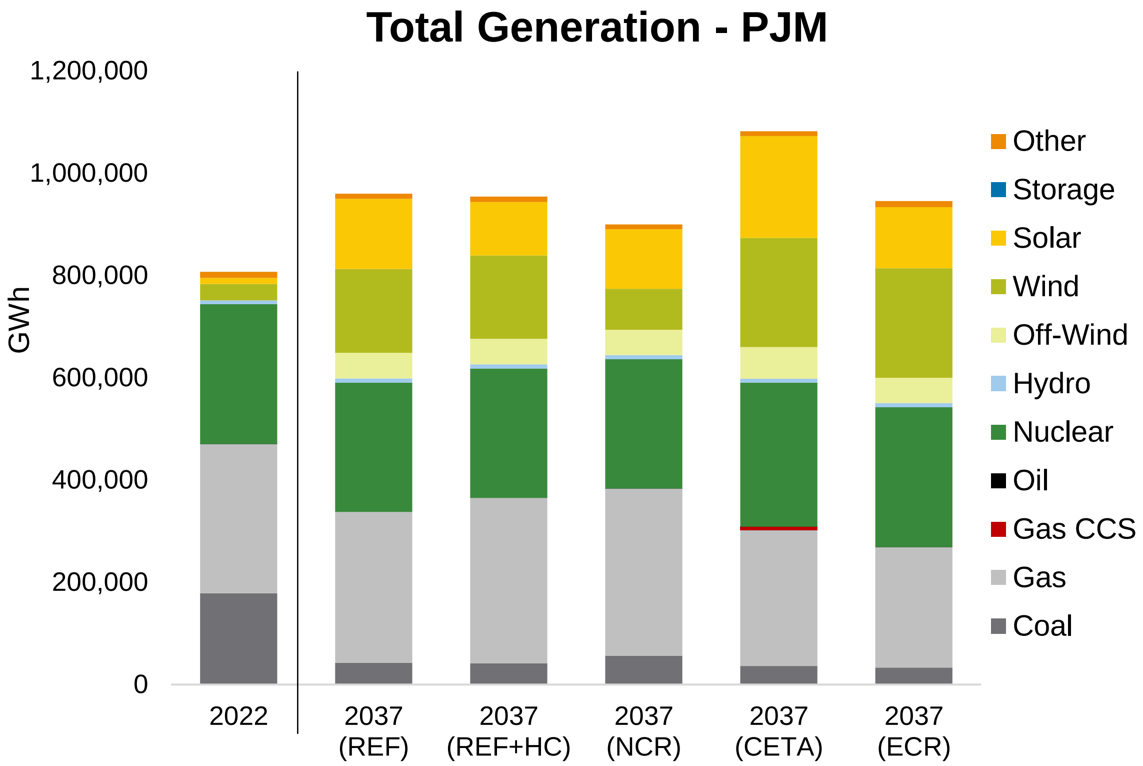
	Scenario Concept	Load	Natural Gas	Carbon	Technology Costs
1	Reference Scenario (REF)	Base	Base	Moderate	Base
2	REF with Higher Unit Cost (REF-HC)	Base	Base	Moderate	Slower Decline
3	Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Faster Decline
4	Enhanced Carbon Regulation (ECR)	Low	High	High	Faster Decline
5	No Carbon Regulation (NCR)	Base	Low	No Price	Base

Note – IRA provisions implemented in all scenarios

CRA Charles River Associates

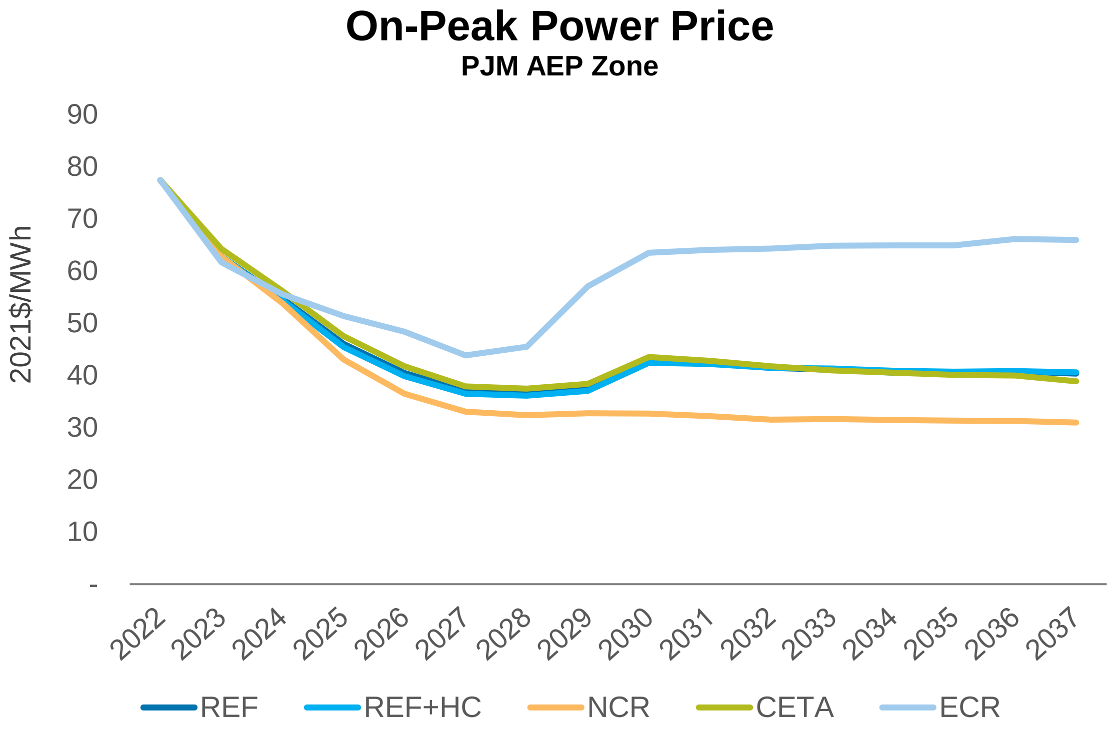
Scenario Results – PJM Supply Mix

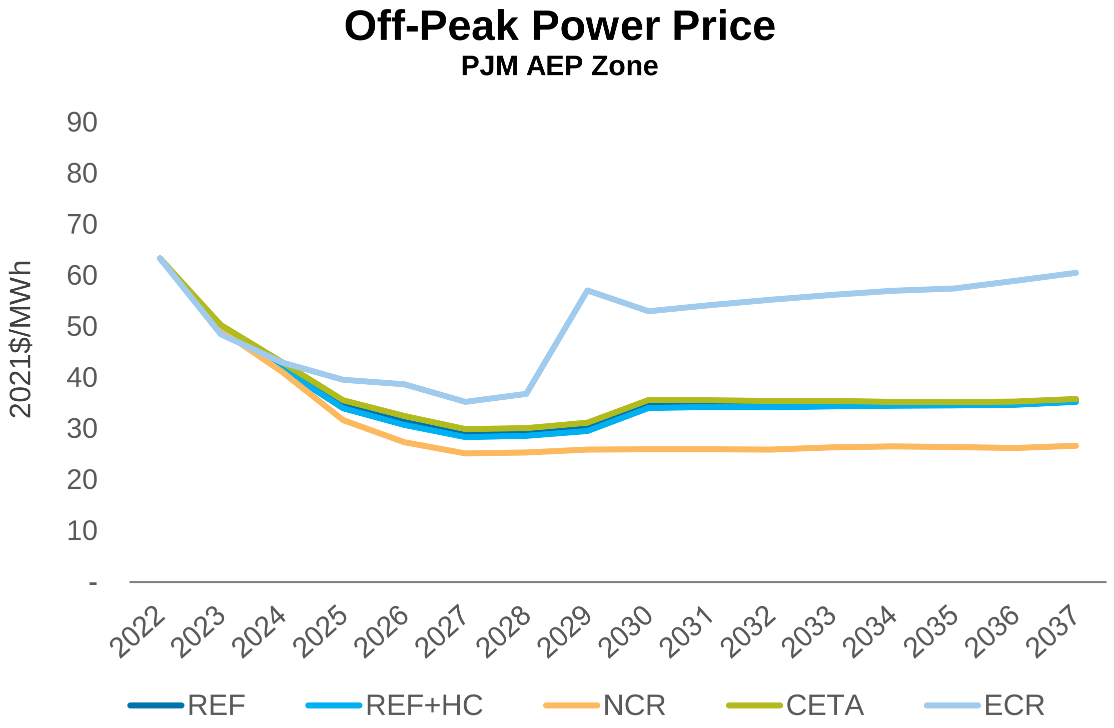




- Under all scenarios, coal capacity declines while the share of gas capacity remains steady in all but the ECR and CETA scenarios
- New additions are focused on wind, solar PV, and 4-hr battery storage, with small amounts of SMR and gas CCS are selected under the CETA scenario
- By 2037, renewable resources 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

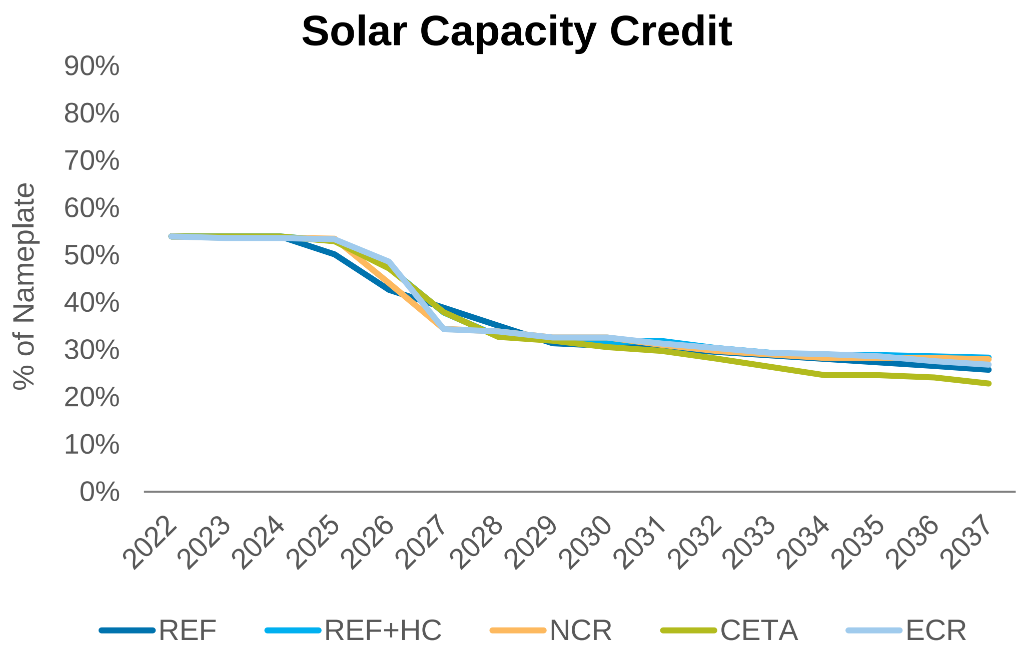


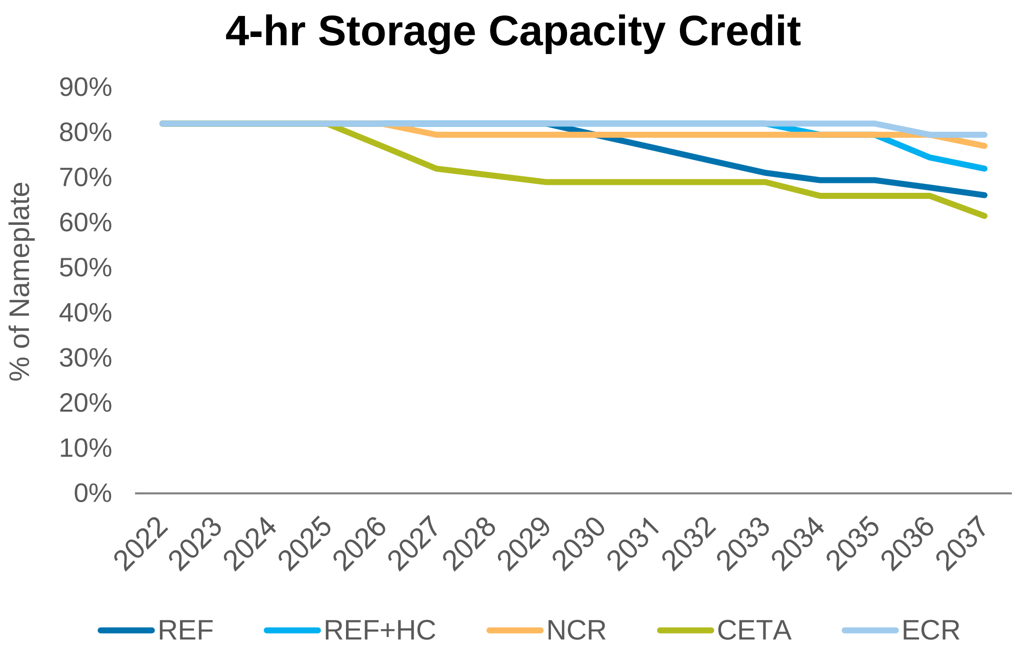


- Under the REF, REF + High Cost, and CETA scenarios, On-Peak prices decrease from current levels until the CO2 price is introduced in 2030, leading to a step-up in prices that hold steady around $40/MWh
- On-Peak prices are lowest in the NCR scenario due to the combination of low gas prices and zero 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)

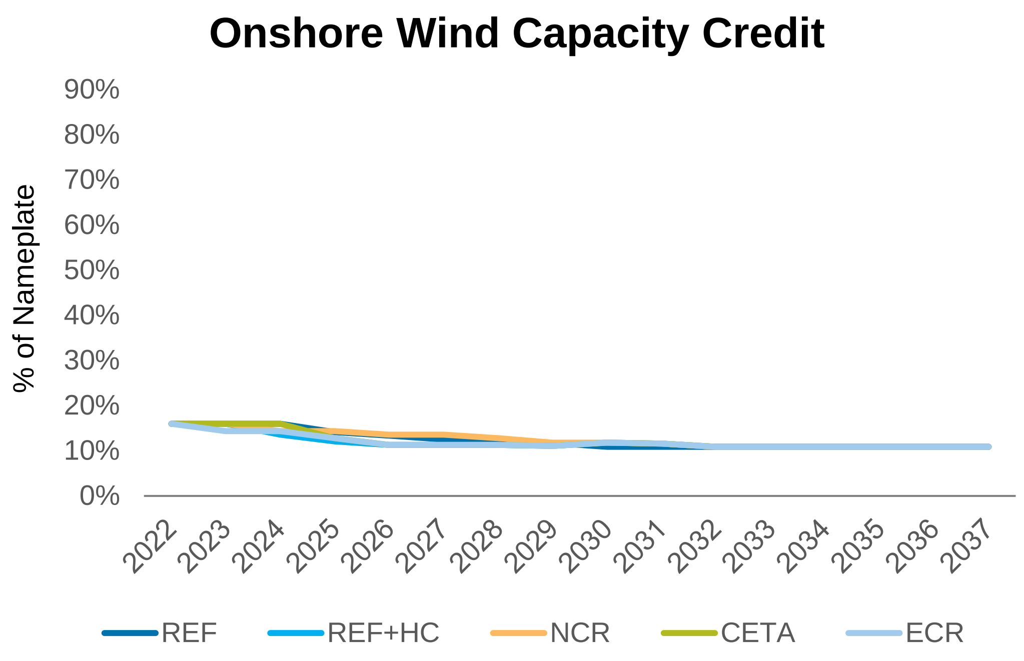


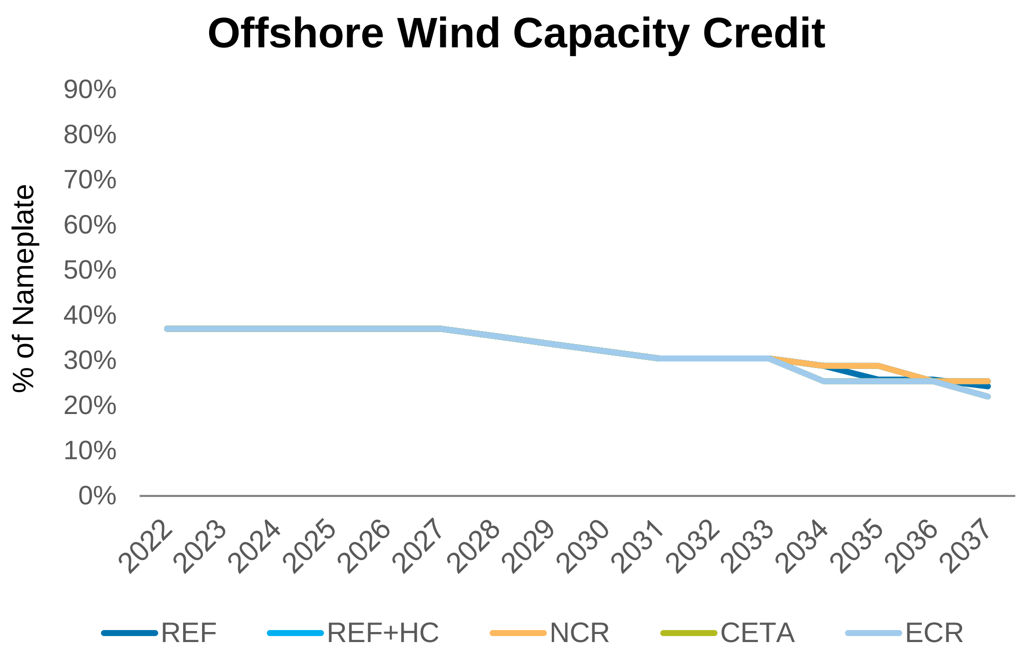


- Under the REF and ECR cases, solar peak credit declines from 54% currently to 26% by 2037
- Under CETA, rapid deployment of new renewables results lower solar peak credit values starting 2031
- Under the NCR Scenario, lower gas prices and lack of CO2 pressure reduce PJM-wide installations, resulting 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



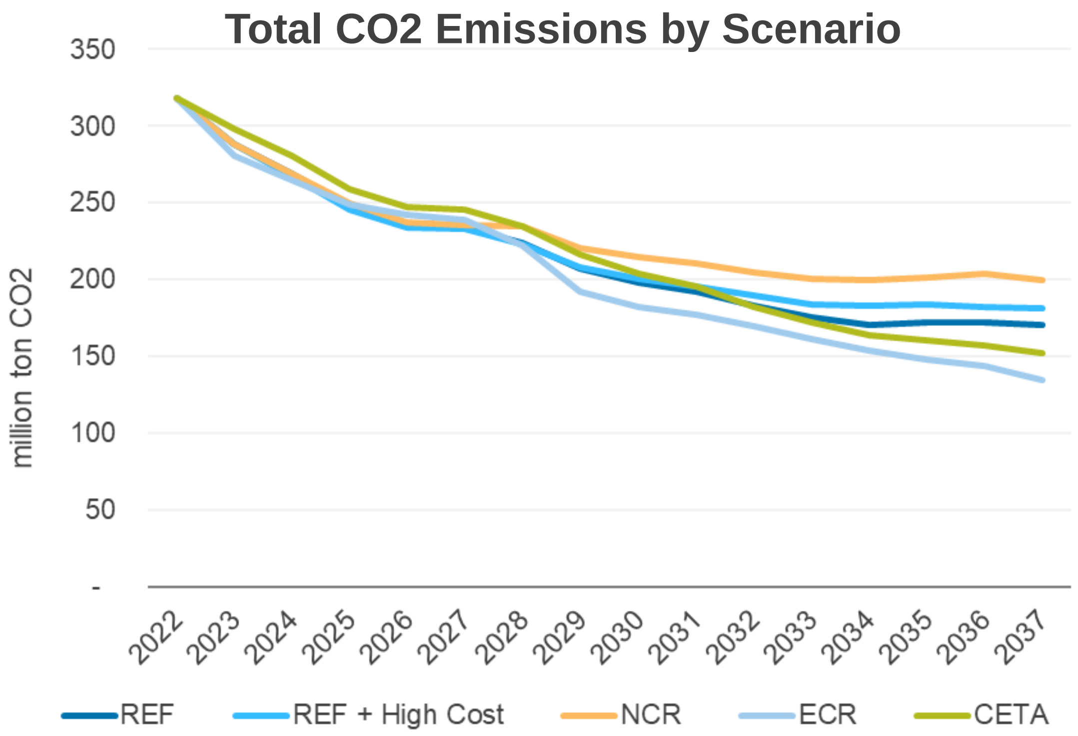


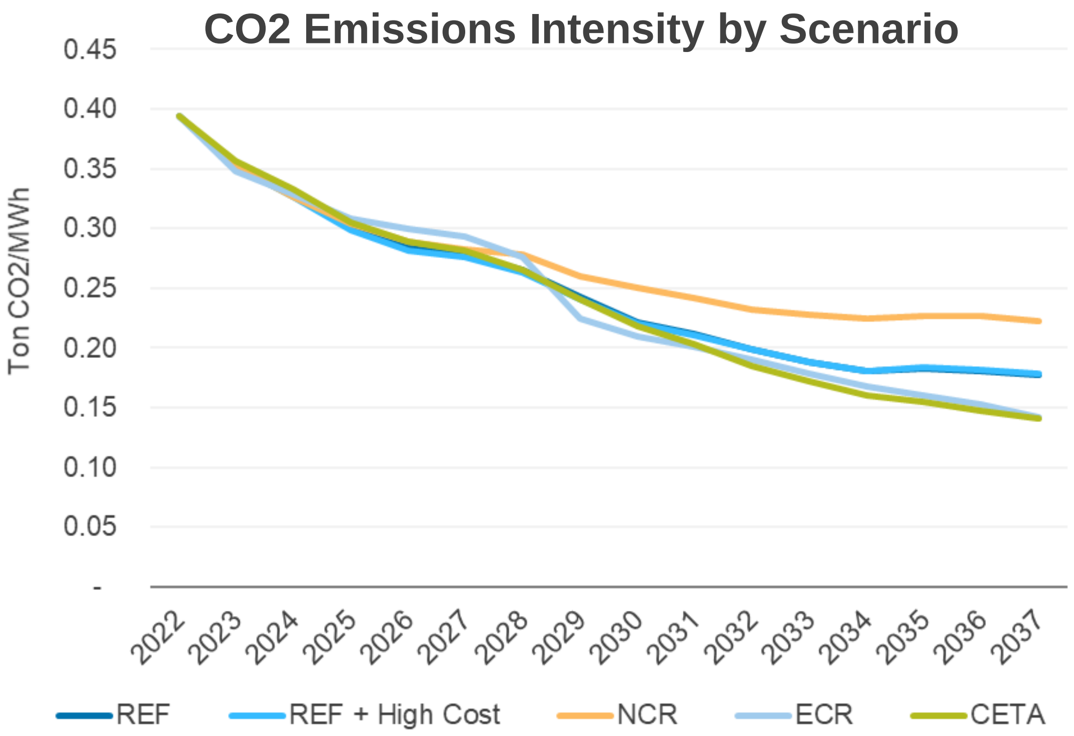
- Across almost all scenarios, Onshore Wind peak credit declines from 16% currently to 11% by 2037
- Under the NCR scenario, lower gas prices and lack of CO2 pressure reduce PJM-wide wind installations, resulting in slower wind peak credit decline between 2024-2030

- 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

KENTUCKY POWER

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

CRA Charles River Associates

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.

IRP Portfolios are developed and evaluated using the Market Scenarios

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

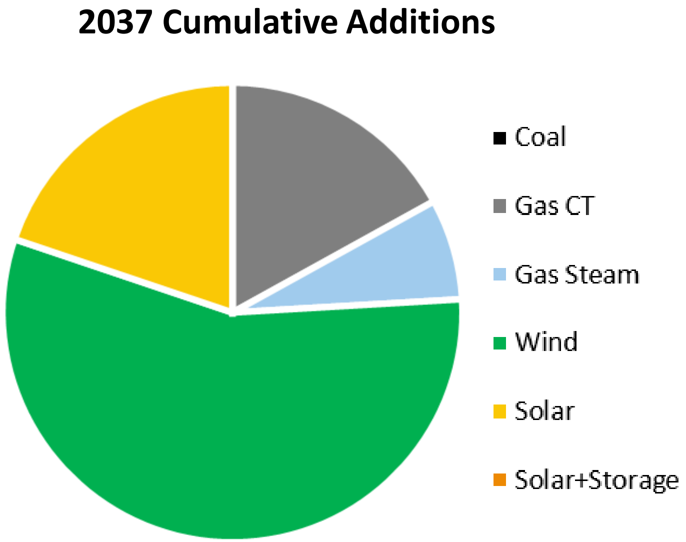
- Reference Scenario
- Reference Scenario with Higher Unit Costs
- Clean Energy Technology Advancement
- Enhanced Carbon Regulation
- No Carbon Regulation

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



CRA Charles River Associates

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%***

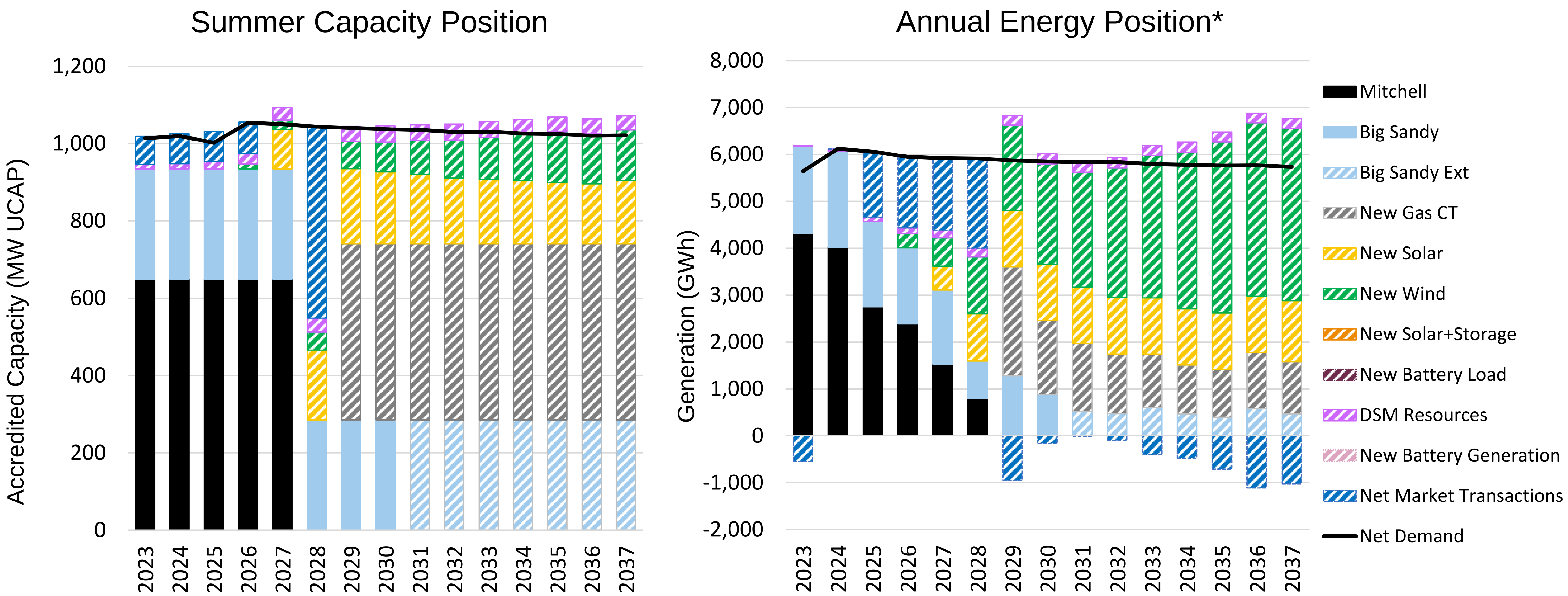
EE Bundle DEVELOPMENT

- 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

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

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.

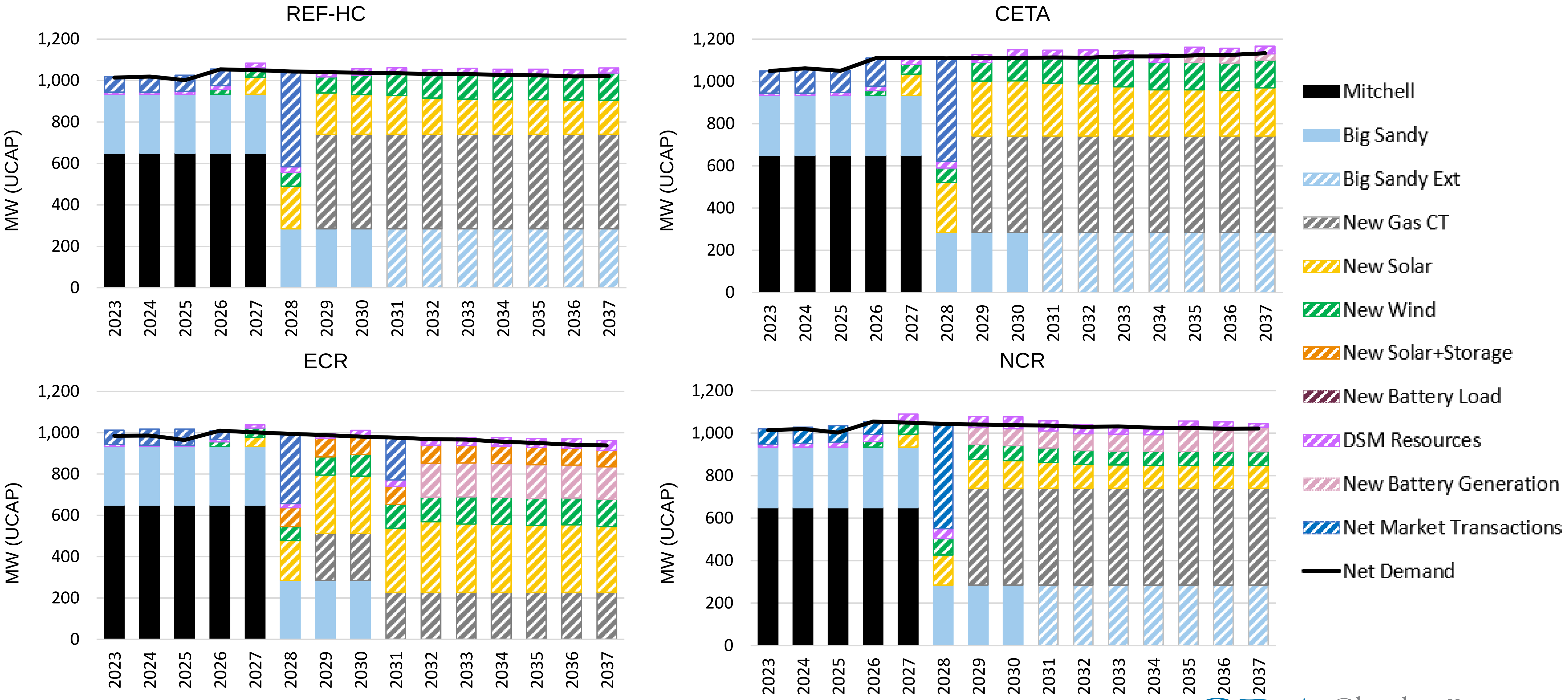
Reference Portfolio Build Detail

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

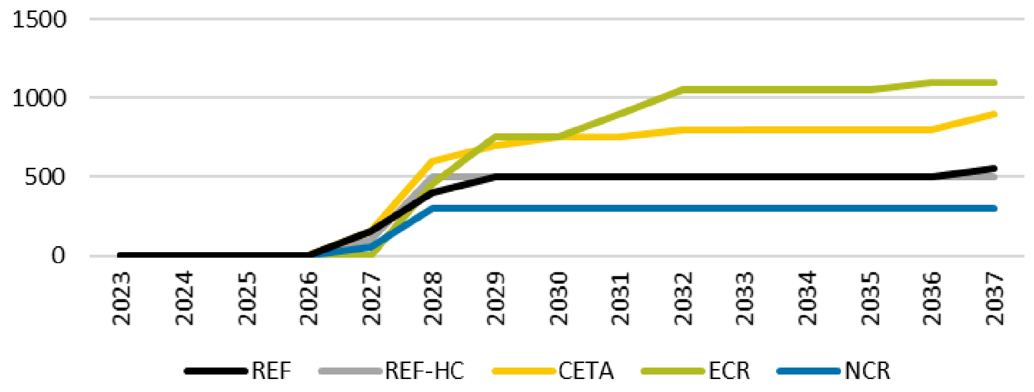
*Capacity purchases in 2023 and 2024 have already been completed

Comparison of Capacity Balance by Portfolio

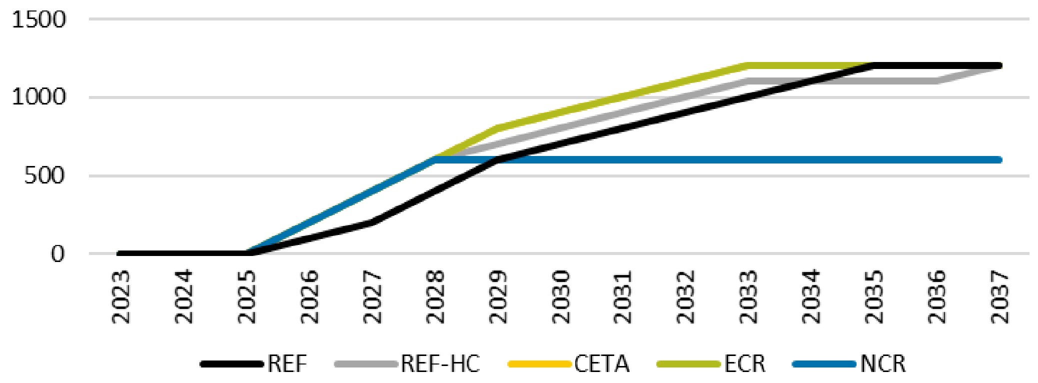


Comparison of New Resource Additions

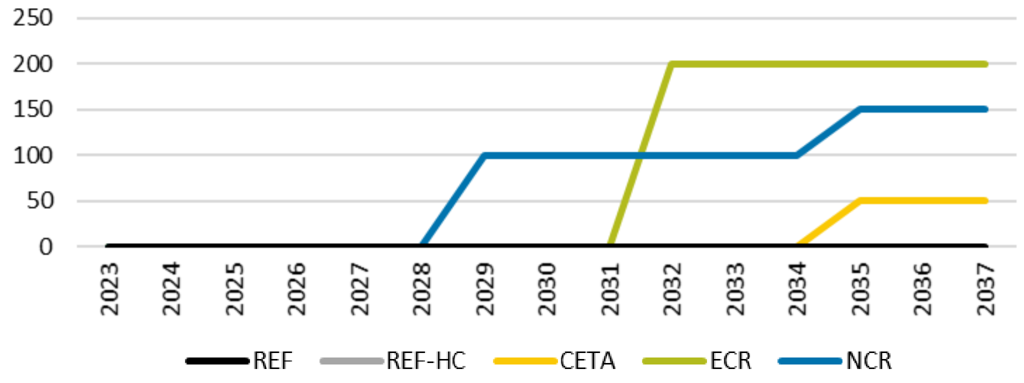
Solar – Cumulative MW ICAP



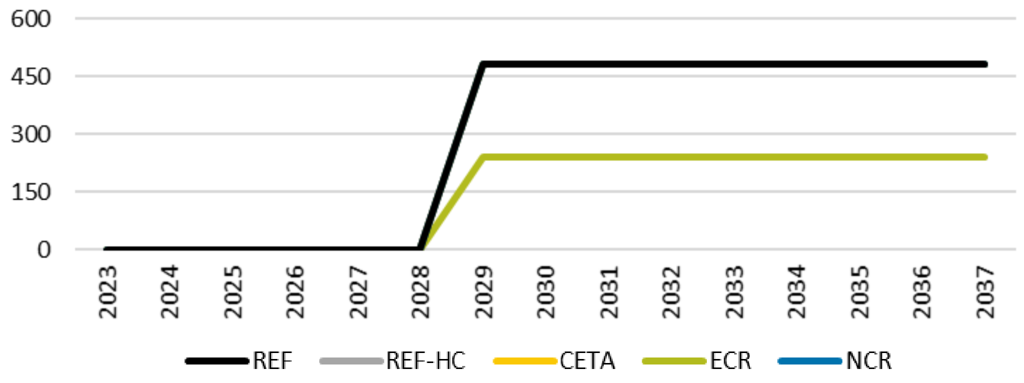
Wind – Cumulative MW ICAP



Storage – Cumulative MW ICAP



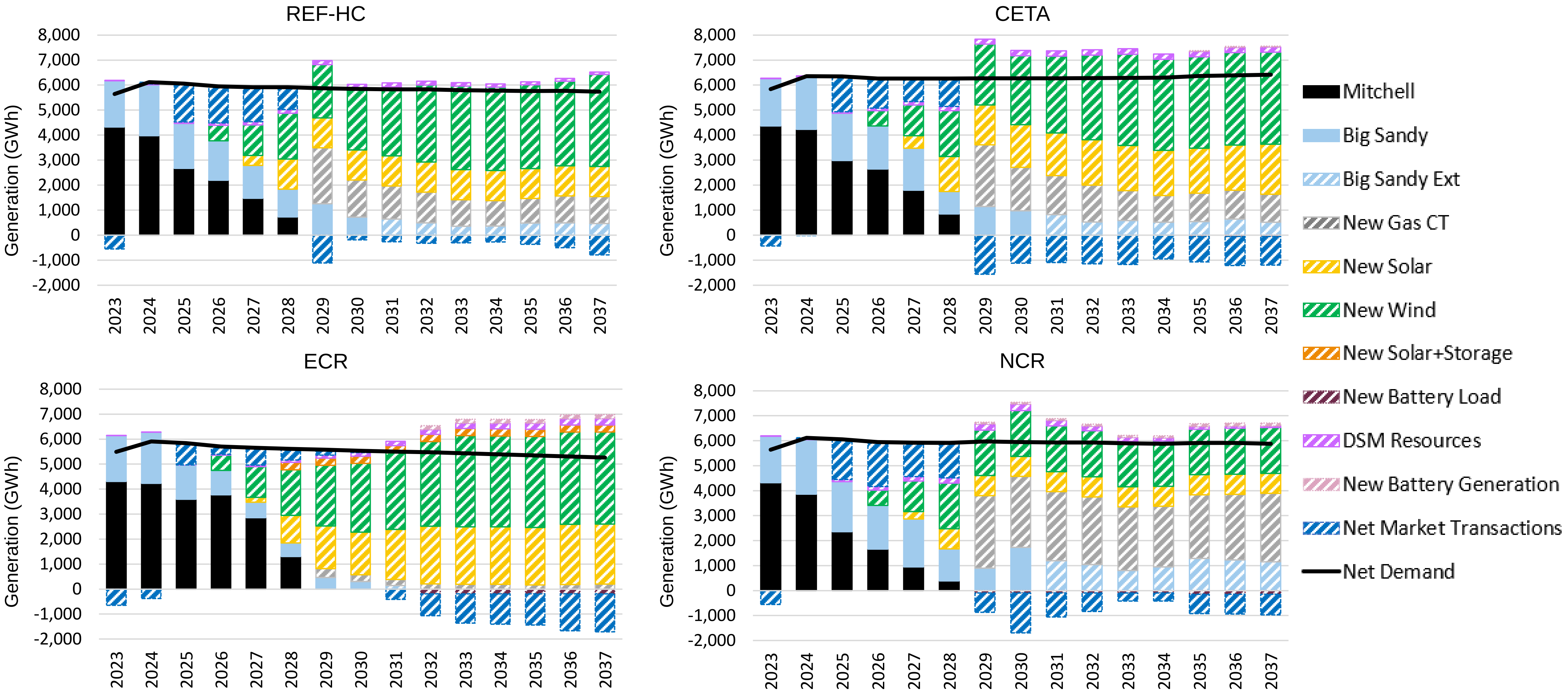
Gas CT – Cumulative MW ICAP



*REF and REF HC have similar solar buildouts and are superimpose. Gas CT buildout is same for all portfolios except ECR.

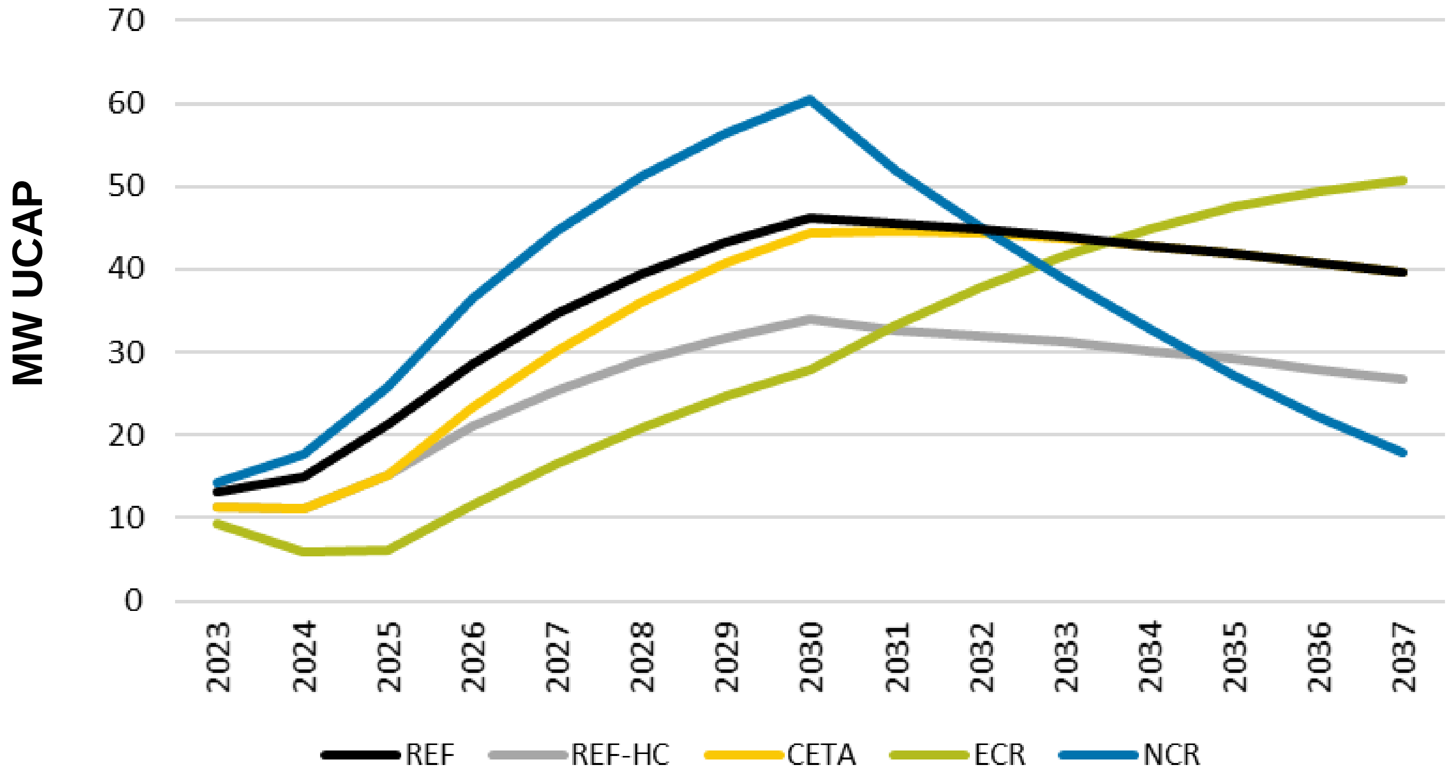
KENTUCKY POWER

Comparison of Energy Balance by Portfolio



CRA Charles River Associates

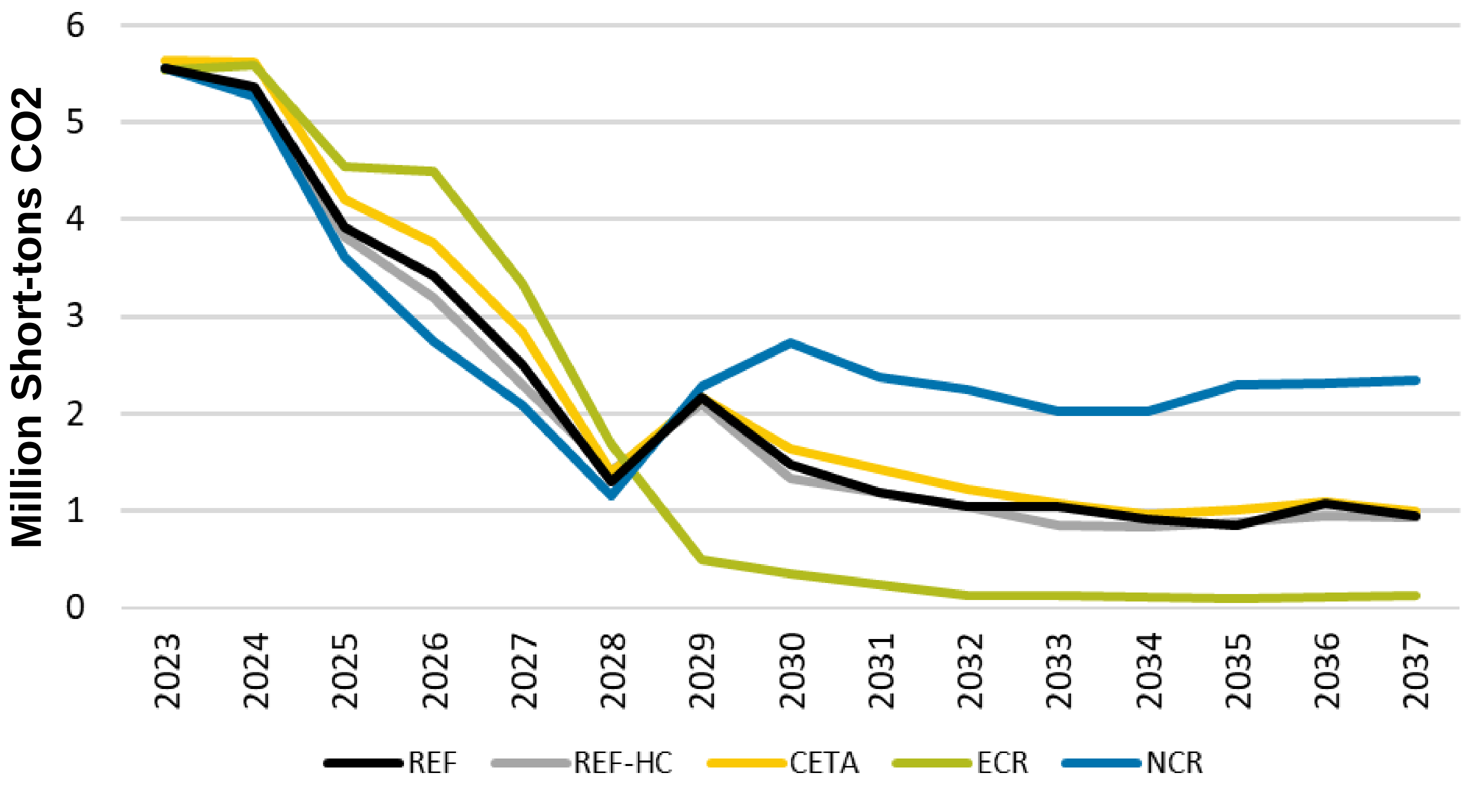
Comparison of DSM Resource



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.

KENTUCKY POWER

Comparison of CO2 Emissions by Portfolio



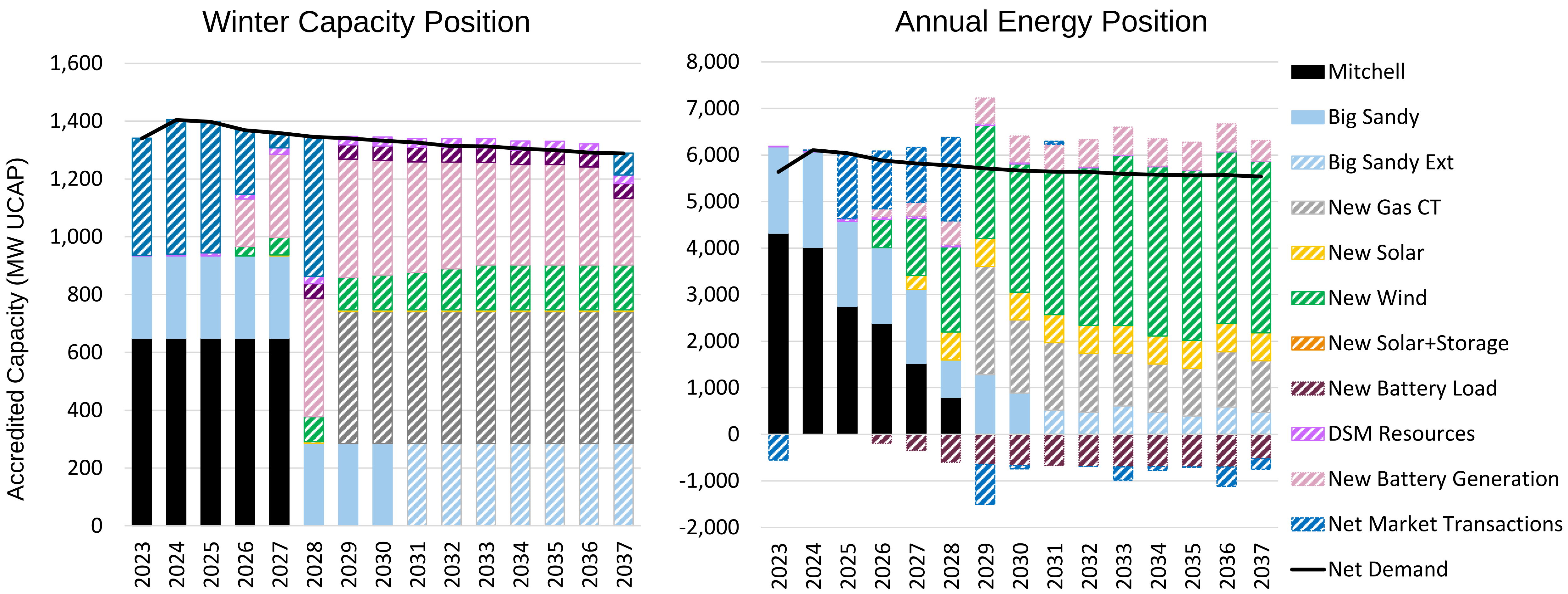
The decline in carbon emissions occurs most drastically in the ECR portfolio under the ECR case due to emissions being regulated through a federal carbon cap and trade program that results in a significant CO_2 price and a long-term power sector net zero trajectory. Each portfolio is shown in their respective scenario.

CRA Charles River Associates

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.

Reference Portfolio Balance - Winter Sensitivity



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.

KENTUCKY POWER

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)

CRA Charles River Associates

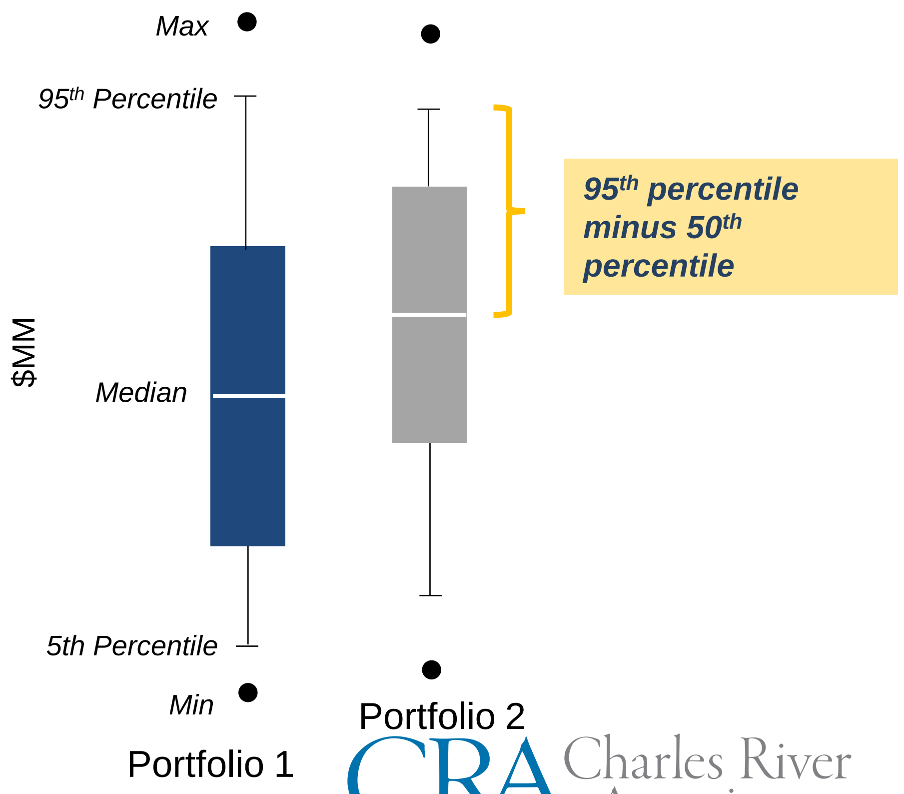
Stochastic Analysis

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



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.

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

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.

KENTUCKY 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.

CRA Charles River Associates

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

KENTUCKY POWER

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.

CRA Charles River Associates

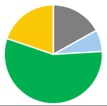
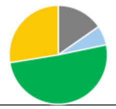
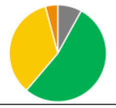
Objective: Maintaining Reliability

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.

KENTUCKY POWER

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	

Coal
Gas CT
Gas Steam
Wind
Solar
Solar+Storage

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).

CRA Charles River Associates

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%

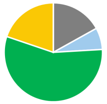
The ECR portfolio scores best by the **Local Impacts** metric on both a MW basis and a dollar basis because of the highest reliance on new renewable and storage resources that tend to be more capital intense than gas-fired units. The CETA portfolio is next best by this metric on the basis of additional 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.

Charles River Associates

KENTUCKY POWER

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.

CRA Charles River Associates

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

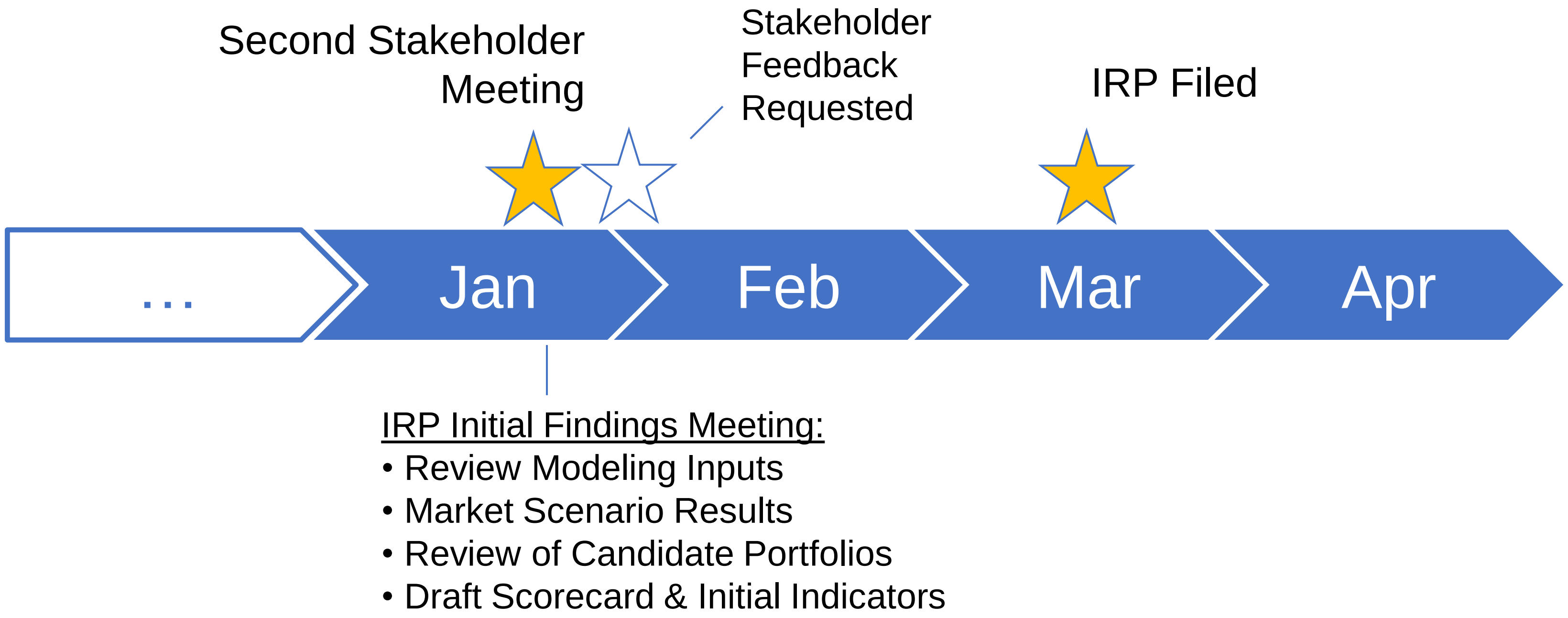
- Welcome and Introductions
- Overview of the 2022 IRP Process
- IRP Modeling Overview
- 2022 IRP Market Scenarios
- Key Inputs to the 2022 IRP
- Market Scenario Results
- Portfolio Development & Results
- Portfolio Risk Analysis
- Scorecard Development
- Discussion & Closing Remarks

Stakeholder feedback is encouraged throughout the presentation.

KENTUCKY POWER

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.



CRA Charles River Associates

Appendix

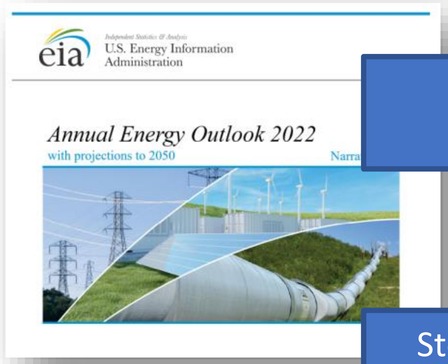
KENTUCKY POWER

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

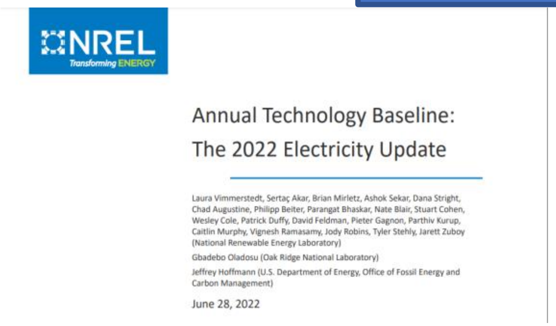

U.S. Energy Information Administration

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

CRA Charles River Associates

KENTUCKY POWER

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

CRA Charles River Associates

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

KENTUCKY POWER

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 CO_2 applicable to geologic storage; $60/ton CO_2 applicable to EOR; $180/ton CO_2 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.

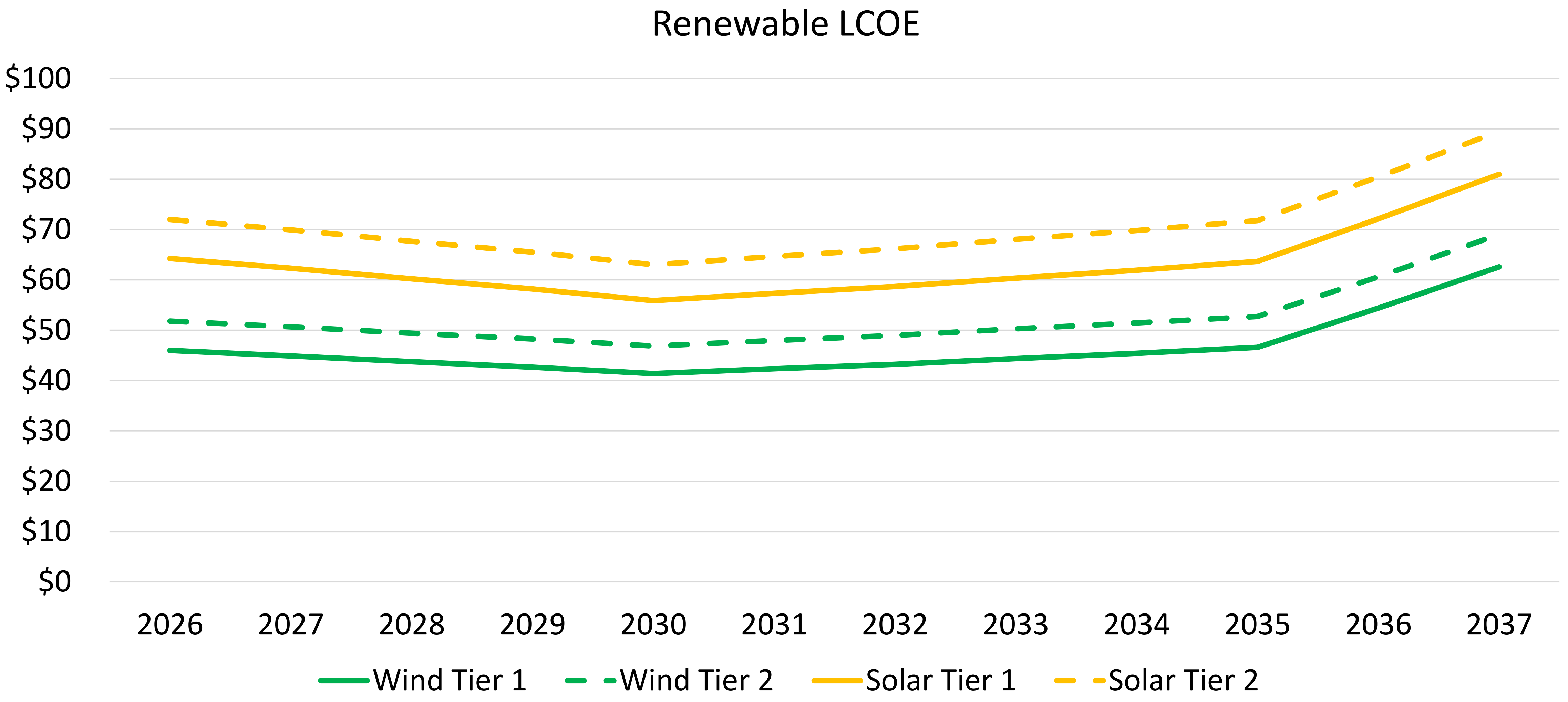
(7) Assumes prevailing wage and apprenticeship requirements are met.

(8) Assuming carbon intensities criteria are met.

CRA Charles River Associates

KENTUCKY POWER

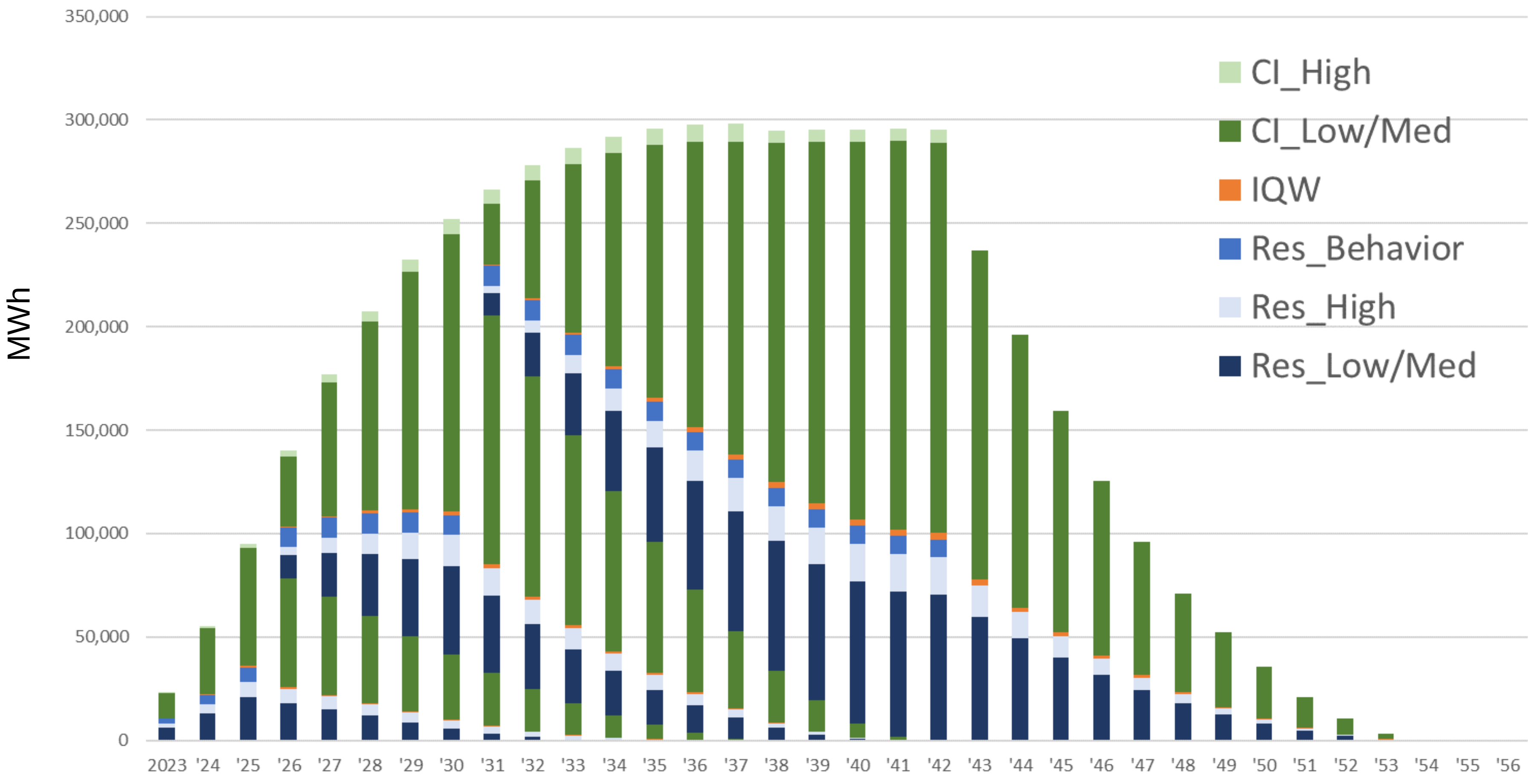
Renewable LCOE – Reference



Charles River Associates

KENTUCKY POWER

EE Bundles - Potential



* *Savings shown are lifetime savings, and extend beyond 2042 IRP horizon*

Levelized $/Lifetime MWh Saved

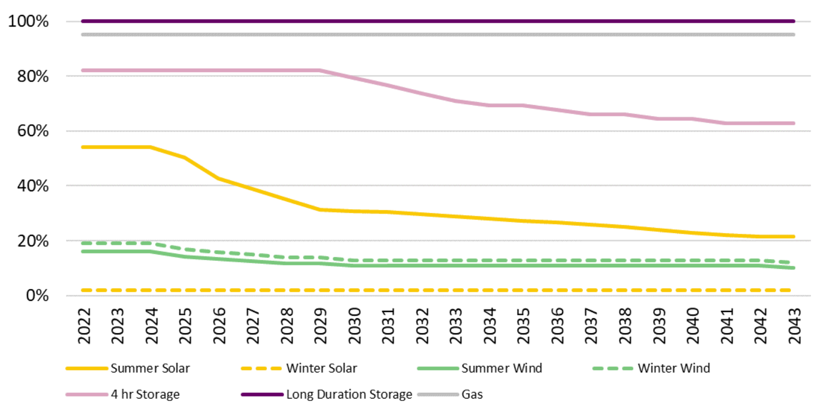
V1	V2	V3
$148	$147	$147
$33	$35	$33
$278	$300	$351
$57	$63	$79
$218	$225	$254
$57	$52	$48

CRA Charles River Associates

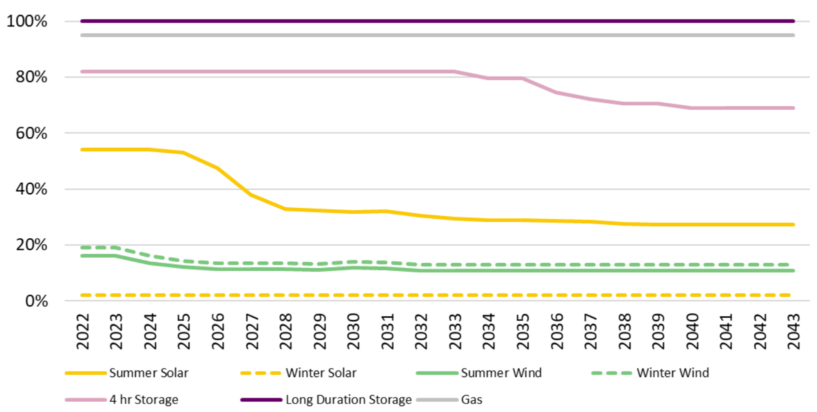
KENTUCKY POWER

Appendix – ELCC Assumptions

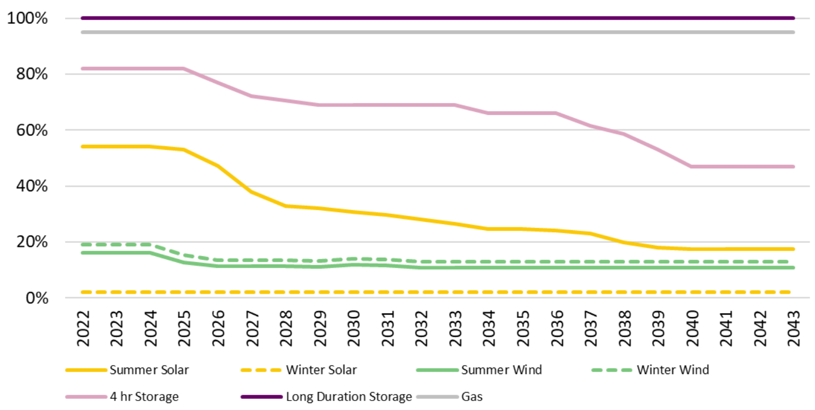
REF



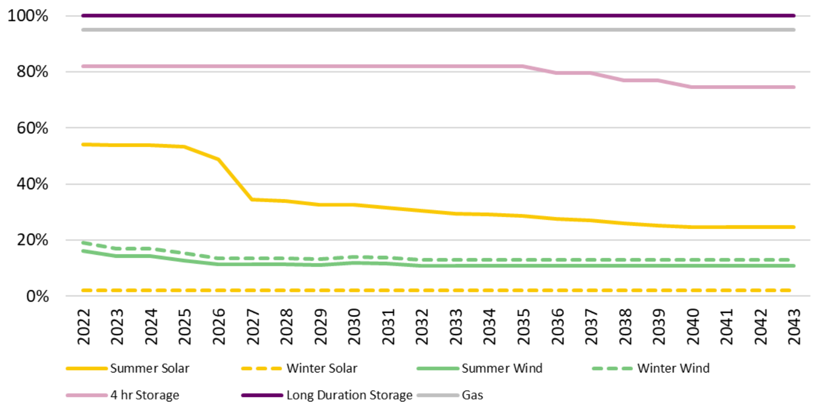
REF-HC



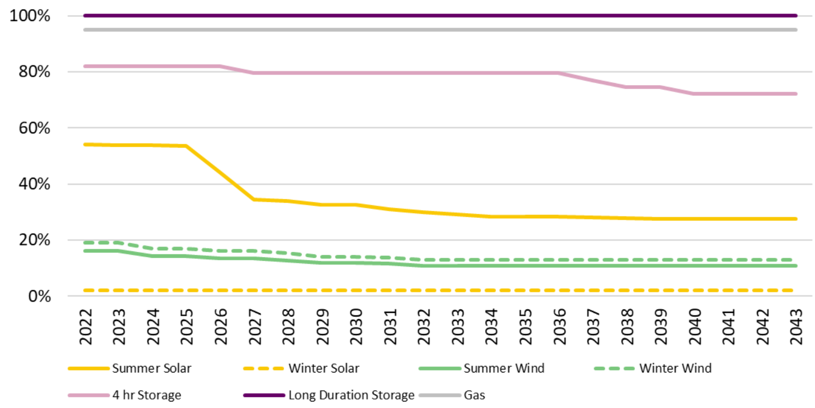
CETA



ECR



NCR



CRA Charles River Associates

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

KENTUCKY POWER

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

CRA Charles River Associates

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

KENTUCKY POWER

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

CRA Charles River Associates

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

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

KENTUCKY POWER

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

CRA Charles River Associates

KP Optimization Results Summery - DSM Selection

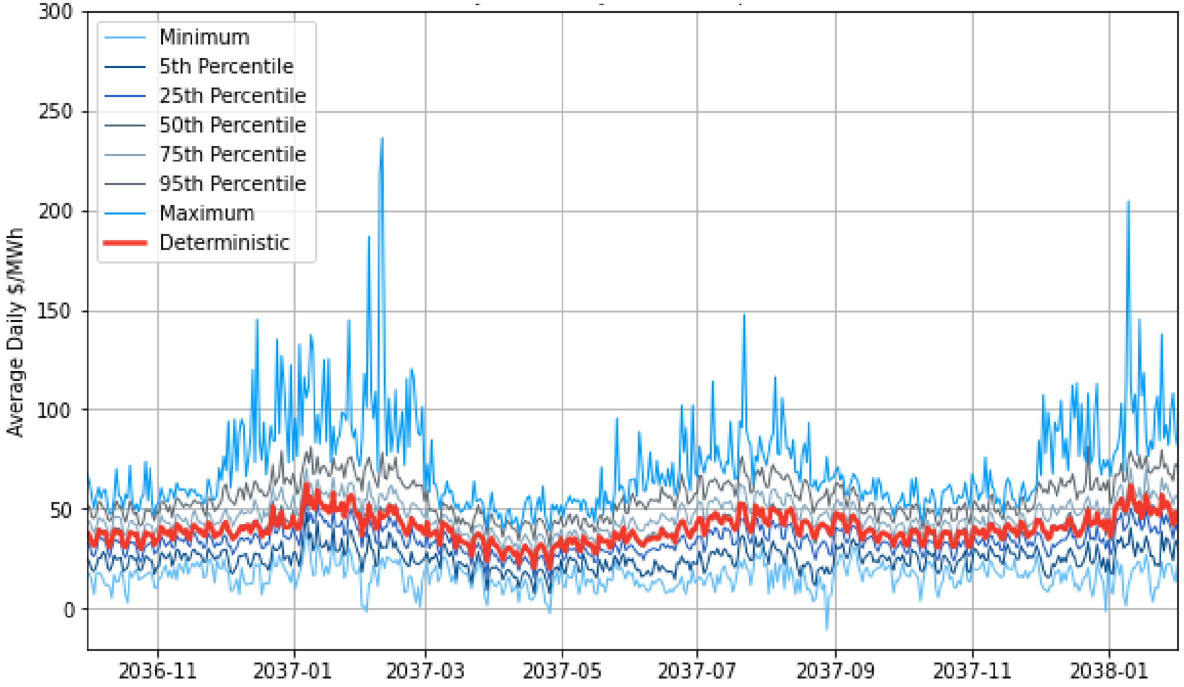
Program Year	DSM Program	REF	REF-HC	CETA	ECR	NCR
2023 - 2025	Residential – Low/Medium 23-25	X				X
	Residential – High 23-25					X
	Residential – Behavior 23-25					
	C&I – Low 23-25	X	X	X		X
	C&I – High 23-25					
2026 - 2030	Residential – Low/Medium 26-30	X		X		X
	Residential – High 26-30					X
	Residential – 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

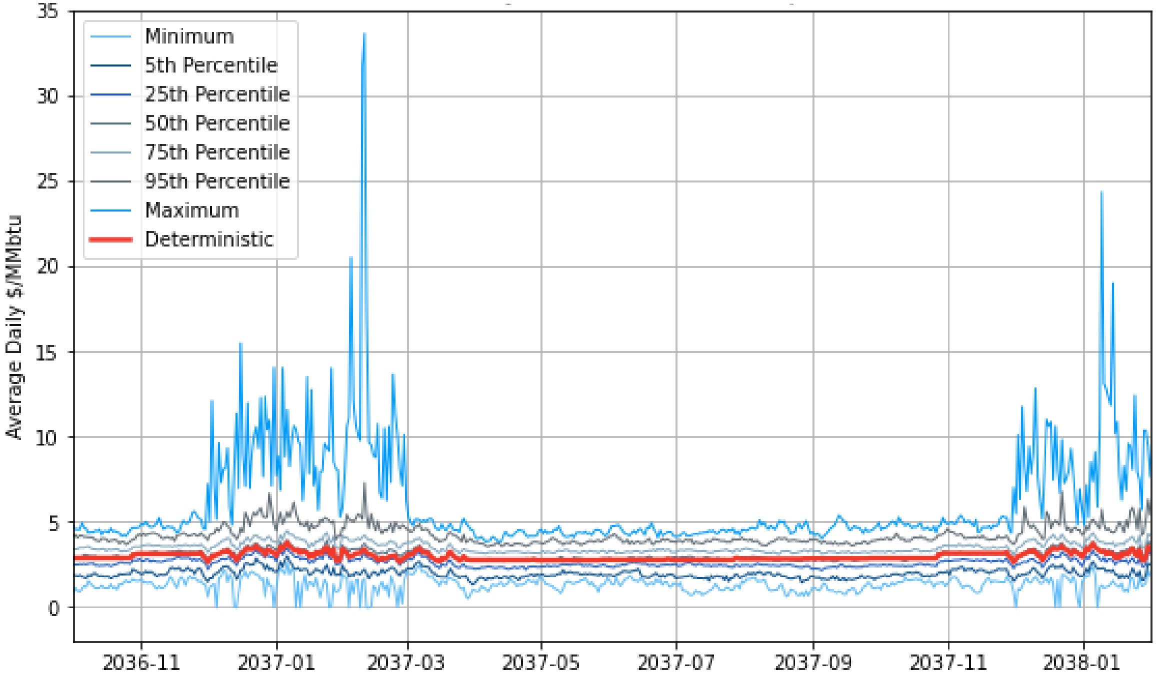
Commodity Price Volatility

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



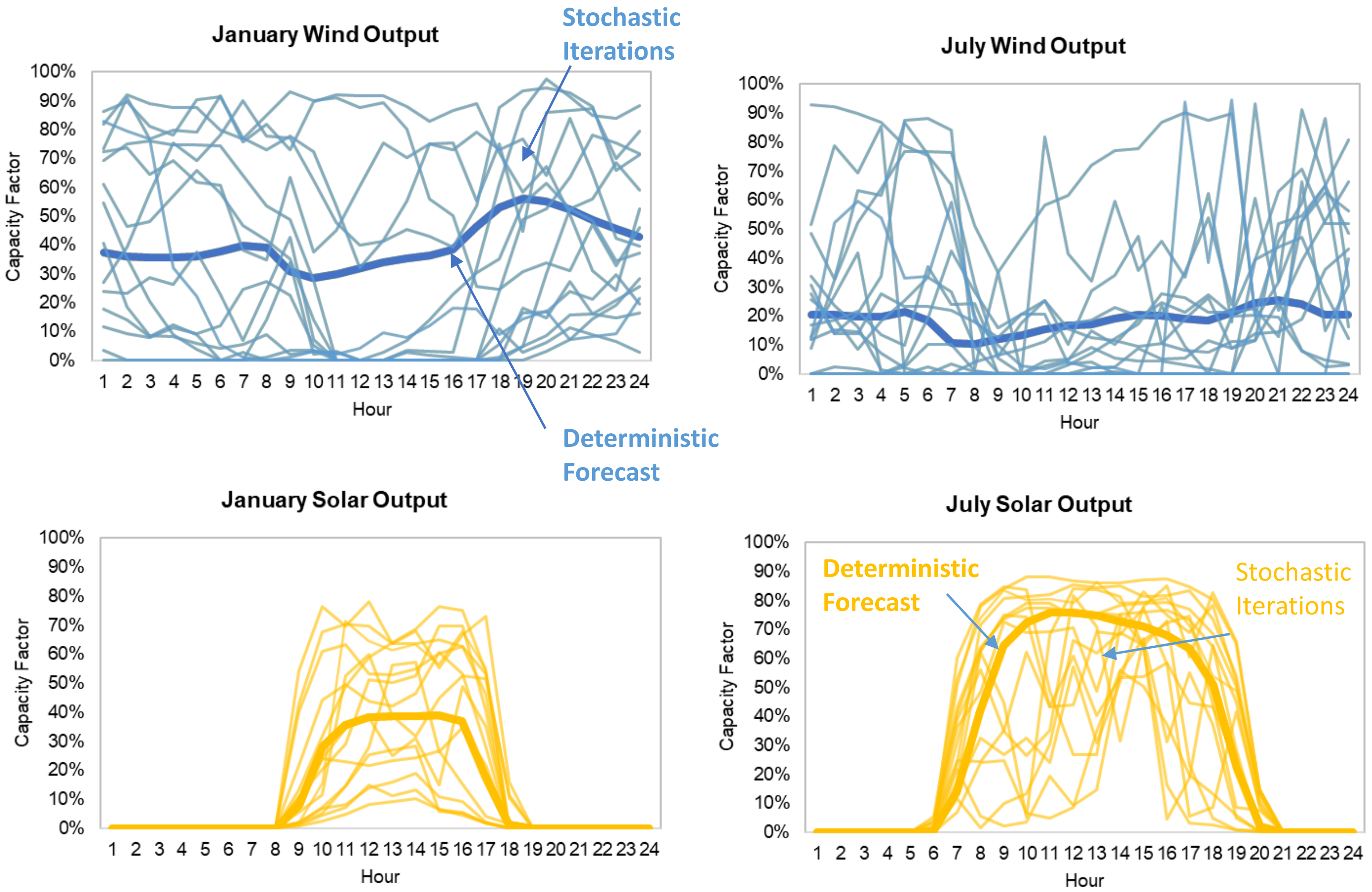
KENTUCKY POWER

Renewable Output Volatility

Kentucky Power evaluated uncertainty in the output of wind and solar resources as part of the 2022 IRP analysis.

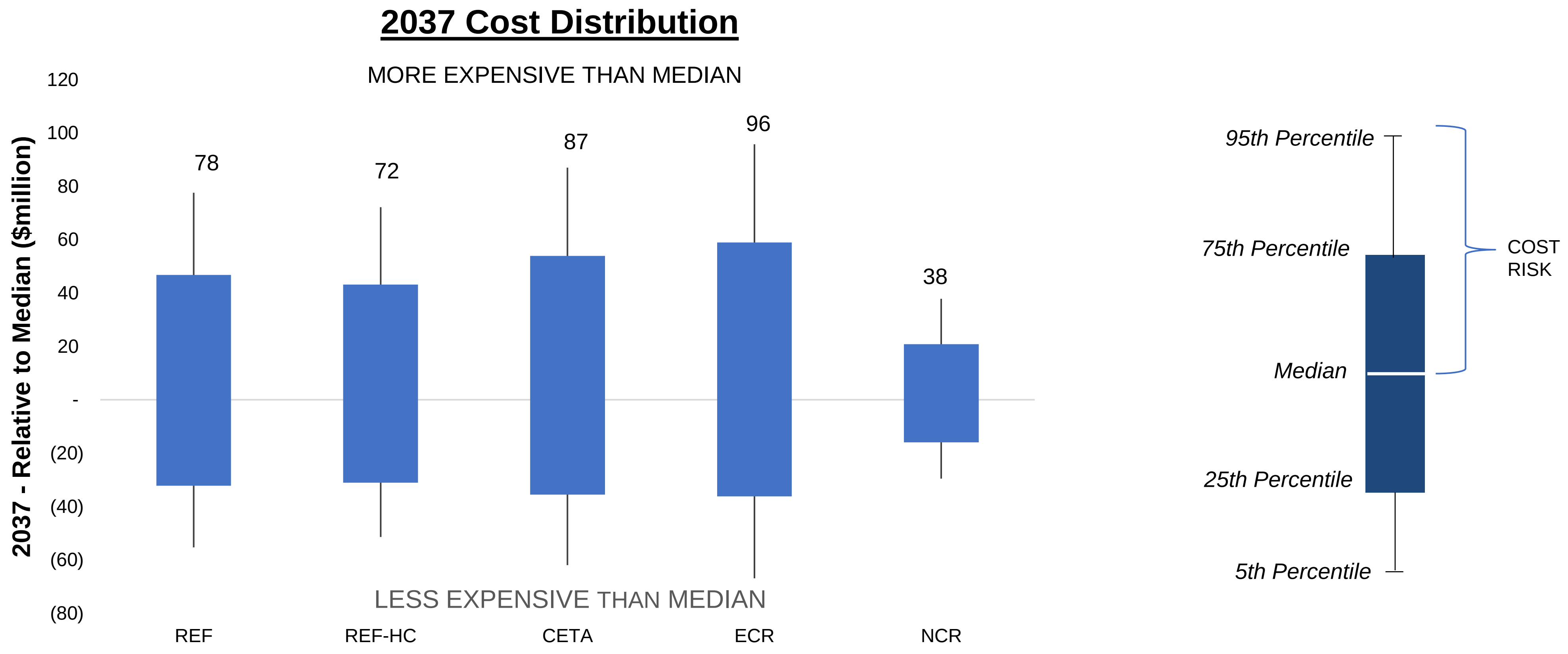
Representative hourly capacity factor shapes for wind and solar were developed using NREL's NSRDB and Wind Toolkit Databases.

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.