KyPSC Case No. 2024-00197
TABLE OF CONTENTS

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Tyler Cook, Engineer III, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Tyler Cook, Affiant

Subscribed and sworn to before me by Tyler Cook on this 4th day of September, 2024.

Jason King
NOTARY ★ PUBLIC
Mecklenburg County, NC

NOTARY PUBLIC

My Commission Expires: 06/15/2028

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Matt Kalemba, Vice President Integrated Resource Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Matt Kalemba Affiant

Subscribed and sworn to before me by Matt Kalemba on this 3rd day of Sept., 2024.

NIMESH R. PATEL NOTARY PUBLIC MECKLENBURG COUNTY, N.C.

NOTARY PUBLIC

My Commission Expires: My Commission Expires Nov. 7, 2024

VERIFICATION

STATE OF KENTUCKY	)	
	)	**SS:**
COUNTY OF JEFFERSON	)	

The undersigned, Dan Sympson, General & Regulatory Strategy Director, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Dan Sympson
Dan Sympson, Affiant

Subscribed and sworn to before me by Dan Sympson on this 3rd day of September, 2024.

Benjamin Berdichevsky
NOTARY PUBLIC

My Commission Expires: 09/20/2027

BENJAMIN BERDICHEVSKY
Notary Public - State at Large
Kentucky
My Commission Expires Sept. 20, 2027
Notary ID KYNP79738

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Matt Peterson, Lead Planning Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Matt Peterson, Affiant

Subscribed and sworn to before me by Matt Peterson on this 4 day of September, 2024.

Katelyn M. Connors
NOTARY PUBLIC

My Commission Expires: July 25, 2026
Mecklenburg County
North Carolina

Katelyn M. Connors
NOTARY PUBLIC
Gaston County, North Carolina

VERIFICATION

STATE OF NORTH CAROLINA)

) SS:

COUNTY OF MECKLENBURG)

The undersigned, Jennifer Poppler, Principal Planning Analyst, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Jennifer Poppler

Jennifer Poppler, Affiant

Subscribed and sworn to before me by Jennider Poppler on this 4 day of September, 2024.

Sadie Griffin

NOTARY PUBLIC

My Commission Expires: 12-05-2028

SADIE GRIFFIN
NOTARY PUBLIC
Cabarrus County
North Carolina
My Commission Expires 12/05/2028

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Matt Ruscio, Director Renewables Development, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Matt Ruscio, Affiant

Subscribed and sworn to before me by Matt Ruscio on this 3rd day of September, 2024.

Linda G. Hart
NOTARY PUBLIC

My Commission Expires: 08-29-2028

LINDA G HART
NOTARY PUBLIC
Union County
North Carolina
Commission # 19930640025
My Commission Expires Aug. 29, 2028

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	SS:
COUNTY OF MECKLENBURG	)	

The undersigned, John D. Swez, Managing Director, Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 28 day of August, 2024.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2028
MECKLENBURG COUNTY, NC

VERIFICATION

STATE OF Texas)
) SS:
COUNTY OF Collin)

The undersigned, Ibrar Khera, Lead Load Forecasting Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Ibrar Khera Affiant

Subscribed and sworn to before me by Ibrar Khera on this 30th day of August, 2024.

NOTARY PUBLIC

My Commission Expires:

TANYA R DAVIS
Notary Public
STATE OF TEXAS
My Comm. Exp. 08-21-27
Notary ID # 13185956-8

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Tim Duff, GM Customer Solutions Regulatory Enablement, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Tim Duff, Affiant

Subscribed and sworn to before me by Tim Duff on this 3rd day of September, 2024.

NOTARY PUBLIC

My Commission Expires:

01/21/29

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-001

REQUEST:

Refer to IRP pages 4-5, Figures 1.2 and 1.3. Provide estimated capital and operations and maintenance (O&M) cost for the portfolios shown in Figures 1.2 and 1.3.

RESPONSE:

Figure 1.2 shows the 2024 Duke Energy Kentucky IRP Preferred Portfolio. The estimated Capital and O&M expenses through 2040 can be found below:

Capital ($000)	$1,083,765
O&M ($000)	$803,722

Figure 1.3 shows the 2024 IRP Without EPA CAA Section 111 Update Portfolio. The estimated Capital and O&M expenses through 2040 can be found below:

Capital ($000)	$1,161,077
O&M ($000)	$752,334

Capital includes Capital Expenses + AFUDC for new units along with Capital Expenses for existing units. O&M includes Variable O&M, Fixed O&M, for both new and existing units along with any additional costs related to Dual Fuel at East Bend Unit 2 including conversion and firm gas transportation costs. Costs shown are represented in 2024 dollars on a PVRR basis using a discount rate of 7.29%.

PERSON RESPONSIBLE: Tyler Cook

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-002

REQUEST:

Refer to the IRP, pages 9. For the Optimized Portfolios on page 9, explain the exact assumptions being imposed in the "With EPA CAA Section 111 Update" scenario or not imposed in the "Without EPA CAA Section 111 Update" scenario that:

a. Would cause Duke Kentucky to model the East Bend dual fuel option (DFO) conversion by 2030 in both scenarios.

b. Would cause Duke Kentucky to model the East Bend Natural Gas Conversion by 2030 in both scenarios.

c. For both the DFO and Natural Gas Conversion of East Bend in each scenario, once the conversion is complete, explain the modeled retirement date of East Bend.

d. In the "Without EPA CAA Section 111 Update" scenario, explain the rationale for modeling the East Bend DFO conversion and the Natural Gas Conversion.

RESPONSE:

a. As shown in Table 3.2 "EPA CAA Section 111 Update" and explained further on page 30 of the Duke Energy Kentucky IRP, one compliance pathway for existing coal under the CAA Section 111 Update is to add 40% gas co-fire capability by 2030. The Company modeled 40% gas co-firing at East Bend as one potential compliance pathway.

b. As shown in Table 3.2 "EPA CAA Section 111 Update" and explained further on page 30 of the Duke Energy Kentucky IRP, another compliance pathway for existing coal under the CAA Section 111 Update is to fully convert the unit to 100% natural gas by 2030. The Company modeled 100% natural gas conversion at East Bend as one potential compliance pathway.

c. For existing coal, those units that add 40% gas co-firing capability by 2030 must retire by 1/1/2039. In that 40% gas co-firing case, under the CAA Section 111 Update, the IRP assumes that East Bend retires on 12/31/2038. In order to operate beyond 2039, East Bend would need to convert to 100% natural gas by 2030. If converted to 100% natural gas by 2030, the IRP assumes that East Bend natural gas unit would retire beyond the planning horizon in 2045 in both the "With EPA CAA Section 111 Update" and "Without EPA CAA Section 111 Update".

   In the "Without EPA CAA Section 111 Update," the 12/31/2038 retirement date was used in the 40% gas co-firing case to reflect that while gas co-firing does add some fuel security to the Duke Energy Kentucky system above maintaining 100% coal operations beyond 2035, maintaining reliable coal operations will become more challenging as the plant nears 60 years of age at the end of the 2030s. Additionally, retiring within the planning horizon does allow for a better assessment of the costs of this gas co-firing plan compared to the "Without EPA CAA Section 111 Update" base plan where East Bend is retired in 2035.

d. East Bend DFO conversion and natural gas conversion were modeled in the "Without EPA CAA Section 111 Update" to assess the cost and operating impacts to the plan if these projects were in place after a stay and eventual remanding of the Section 111 Update. As stated in the IRP on page 5, a number of parties have challenged the rule and filed motions to seek a stay. It is not clear if these parties will be successful, nor is it clear that, if they are successful in being granted a stay, when or if the rule be remanded. The Companies therefore assessed the impacts to the plan if these projects were in place after the Section 111 Update were eventually remanded.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-003

REQUEST:

Refer to the IRP, pages 9–10.

a. For the carbon capture and sequestration (CCS) technology, DFO, and full gas conversion modifications of the East Bend generator on page 9 and for each alternate scenario on page 10, provide a discussion of the planning, engineering, and construction timelines including putting Duke Kentucky into reservation queues for suppliers and construction crews, leading up to when each East Bend modification is complete.

b. Assuming that "Without EPA CAA Section 111 Update" scenario ultimately proves to be true, for each potential East Bend generator modification explain how far along in the planning and construction process Duke Kentucky will have gone before it reaches the point of no return and each particular modification (CCS, DFO, and full gas conversion) is carried out.

RESPONSE:

a. Duke Energy Kentucky subject matter experts have developed high-level timeline guidance for the East Bend modification scenarios listed on pages 9 and 10. Full natural gas conversion and DFO conversion projects assume a detailed engineering study is executed following initial portfolio level selection. Once the study is completed and permitting has been submitted, a Certificate of Public Convenience and Necessity (CPCN) will be filed with the Kentucky

Public Service Commission. Once detailed engineering will be completed and once the CPCN is approved, equipment procurement and construction activities can be started. When construction is complete, commissioning and testing of the systems will commence once natural gas is available at the site. In parallel to the plant-side modifications, a new lateral will be constructed to supply natural gas to the site. Additionally, the gas supplier may need to complete mainline expansion projects in order to support the potential daily gas demand required by the conversion project. It is expected the entire duration of both of these activities is 4-5 years. Additional details on equipment and construction reservation or queues will be understood once the engineering study is complete. Note that CCS was not considered an option for East Bend in the timeline which the EPA CAA Section 111 rules require and is not listed as an option on pages 9 or 10.

b. Generally, the point at which the company is committed to moving forward with a project is once conversion equipment has been ordered, construction contracts are executed, and when full notice to proceed on natural gas lateral and mainline expansion projects is released. At that point the engineering studies and design have been completed, permits have been applied for and the CPCN(s) have been approved.

PERSON RESPONSIBLE: Dan Sympson

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-004

REQUEST:

Refer to IRP, pages 11–12, regarding generation technology cost projections and resource options.

a. Provide any Requests for Proposals (RFPs) and responses, if any, submitted or received by Duke Kentucky and used in determining cost projections.
b. If no RFPs were submitted, explain why.
c. Identify which resource option cost projections were based on self-build cost and which were not.

RESPONSE:

a. Duke Energy Kentucky has not recently issued an RFP.
b. Existing Duke Energy Kentucky capacity (resources) is sufficient to serve forecasted load in the near term and has not identified a need for enough additional resources to justify an issuance of an RFP.
c. In IRP modeling the Company made no distinction between which resources were self-built and which ones were not. A generic resource cost was assumed based on resource type, region, and construction time.

PERSON RESPONSIBLE: Dan Sympson – a., b.
Matt Peterson – c.

CONFIDENTIAL STAFF-DR-01-005
(As to Attachment only)

REQUEST:

Refer to the IRP, page 12.

a. Provide the cost and operational characteristics for each technology resource made available to the EnCompass model in the economic optimization modeling process. Also include with the response as a separate technology/resource option, any potential resource that has been modified to accommodate CCS, DFO, or full gas conversion.

b. For the CCS, DFO, and full gas conversion resource options, provide the source of and a description of how the cost data was obtained.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

a. The attached table provides the cost and operational characteristics for each technology resource available to the EnCompass model in the 2024 Duke Energy Kentucky IRP modeling process. Please see STAFF-DR-01-005(a) Confidential Attachment.

In addition to the selectable resources, CCS, DFO and natural gas conversion was made available as retrofit options at East Bend.

b. Coal to gas conversion / dual-fuel costs were based on the company's significant actual project experiences in Carolinas (8 units), scaled as appropriate and then escalated and inflated to reflect today's market conditions.

Engineering studies would need to be conducted to determine the necessary project scope and gain more accuracy on the projected costs. The cost of a new 1x1 combined cycle with CCS was informed by an external consultant as were the other resources listed in the response to part (a).

PERSON RESPONSIBLE: Matt Peterson

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-001-005(a)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

STAFF-DR-01-006

REQUEST:

Refer to the IRP, Figures 3.1-3.16, pages 15–25. For each Figure, provide the data in excel spreadsheet form with all cells visible and unprotected.

RESPONSE:

Please see STAFF-DR-01-006 Attachment.

PERSON RESPONSIBLE: Matthew Kalemba

Figure 3.1 High, Base and Low Henry Hub Gas Price Forecasts ($/mmBTU)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
High	$5.19	$6.02	$6.17	$6.33	$6.15	$5.91	$6.14	$6.60	$7.02	$7.14	$7.62	$7.84	$8.22	$8.29	$8.63	$8.95	$9.29	$9.44	$9.77	$10.20	$10.40	$10.76	$11.27	$11.61	$12.23	$12.88
Base	$3.31	$3.62	$3.62	$3.64	$3.52	$3.47	$3.63	$3.92	$4.28	$4.43	$4.81	$4.92	$5.21	$5.41	$5.52	$5.93	$6.34	$6.52	$6.79	$7.04	$7.29	$7.60	$7.96	$8.24	$8.59	$9.15
Low	$2.77	$3.10	$3.16	$3.15	$3.08	$3.05	$3.21	$3.45	$3.70	$3.62	$3.81	$3.85	$4.01	$4.06	$4.22	$4.42	$4.67	$4.76	$4.98	$5.22	$5.35	$5.54	$5.88	$6.19	$6.49	$6.87

Figure 3.2 High, Base and Low coal Price Forecasts (east Bend Devivered Coal Price ($/mmBTU)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
High	$2.65	$2.75	$2.85	$2.93	$2.99	$3.14	$2.90	$3.04	$3.14	$3.32	$3.45	$3.62	$3.74
Base	$2.56	$2.64	$2.74	$2.82	$2.90	$2.94	$2.98	$3.00	$3.09	$3.21	$3.33	$3.46	$3.60
Low	$2.48	$2.46	$2.45	$2.52	$2.60	$2.68	$2.61	$2.75	$2.82	$2.95	$3.08	$3.20	$3.29

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
High	$3.82	$3.94	$4.12	$4.22	$4.42	$4.59	$4.67	$4.85	$4.96	$5.21	$5.51	$5.59	$5.81
Base	$3.67	$3.81	$3.96	$4.03	$4.19	$4.35	$4.44	$4.61	$4.70	$4.89	$5.09	$5.16	$5.37
Low	$3.31	$3.37	$3.44	$3.49	$3.57	$3.68	$3.69	$3.78	$3.82	$3.99	$4.08	$4.03	$4.07

Figure 3.3 **PJM Expasion Plan with the EPA CAA Section 111 Update, Base Fuels, Nameplate Capacity (GW)**

Nameplate Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Battery	3,156	3,961	4,347	4,750	5,130	6,586	6,994	7,596	8,445	8,850	10,586	10,576	10,546
Coal	35,329	29,349	28,903	26,718	22,680	20,385	16,582	8,644	7,345	5,347	1,711	1,062	1,062
Combined Cycle	57,238	58,188	58,018	66,124	70,917	74,516	75,691	80,759	86,112	88,903	91,613	91,642	92,540
Combustion Turbine	24,742	24,665	24,639	24,189	24,114	24,043	23,932	23,123	22,781	22,781	22,581	22,315	22,181
Nuclear	32,995	31,730	29,531	29,531	29,531	27,578	27,578	27,578	25,752	23,506	23,661	21,098	20,356
Other	26,622	26,501	27,163	27,646	28,236	27,816	27,118	28,084	28,607	30,002	31,354	32,595	34,217
Solar PV	34,611	40,448	41,604	42,776	43,954	48,043	50,013	55,689	63,341	71,163	76,824	82,503	88,404
Wind	29,572	29,572	29,572	29,572	29,572	30,153	32,153	34,153	36,153	38,153	40,153	42,153	44,153
Wind - Offshore	12	2,893	4,751	5,348	5,939	6,782	7,360	7,965	8,513	9,234	10,896	10,913	12,059

Nameplate Capacity (MW)	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	10,536	10,184	9,917	9,717	10,206	10,196	10,525	10,513	11,078	10,915	10,718	10,877	11,394
Coal	1,062												
Combined Cycle	91,611	91,359	91,395	91,010	91,529	90,855	92,013	92,013	93,027	93,027	93,027	92,588	91,282
Combustion Turbine	22,168	21,792	21,107	20,372	19,488	18,803	18,803	18,715	18,626	18,617	18,538	17,364	15,003
Nuclear	19,198	19,536	19,207	19,207	17,331	17,331	15,813	17,204	16,619	15,755	15,755	14,565	14,565
Other	36,095	38,135	40,197	42,289	44,482	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	95,087	100,802	108,660	115,944	125,427	134,421	143,790	153,085	161,583	168,441	175,647	183,334	192,147
Wind	46,153	47,672	47,672	47,672	47,672	47,672	47,672	47,672	47,952	49,952	51,952	51,952	53,695
Wind - Offshore	13,505	15,455	16,701	17,715	18,939	20,347	22,119	26,185	26,777	28,245	30,983	33,284	38,193

Figure 3.4 **PJM Generation with the EPA CAA Section 111 Update, Base Fuels, Generation (Gigawatt-hour (GWh)**

Generation (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Battery	-677	-899	-967	-1,015	-1,085	-1,416	-1,509	-1,389	-1,620	-1,803	-2,191	-2,223	-2,243	-2,268	-2,227	-2,219	-2,175	-2,326	-2,334	-2,405	-2,455	-2,552	-2,490	-2,478	-2,527	-2,666
Coal	88,719	90,424	90,578	74,593	61,145	51,330	44,739	31,598	25,196	17,264	6,371	3,389	3,505	3,564												
Combined Cycle	311,184	310,943	321,693	355,138	377,602	402,687	411,306	414,810	432,986	437,470	444,835	459,133	456,571	451,194	433,630	419,524	411,160	408,192	401,397	382,041	364,788	356,558	348,423	334,348	328,788	306,529
Combustion Turbine	19,373	16,844	20,197	12,601	10,278	9,837	8,975	6,956	3,690	2,969	1,752	2,171	2,493	2,650	2,057	1,693	1,409	1,151	1,148	755	759	591	585	605	454	374
Nuclear	265,511	258,988	236,780	237,972	239,204	219,253	222,202	222,717	205,032	199,313	191,976	179,748	166,209	155,885	155,717	158,735	156,653	146,807	138,567	141,869	139,010	139,613	132,933	128,719	122,897	118,810
Other	20,327	18,731	19,124	16,576	16,169	15,727	13,306	13,395	12,629	12,309	11,904	10,519	10,142	9,788	9,153	8,676	8,350	7,348	6,902	6,324	5,602	5,360	4,774	3,926	3,149	2,211
Solar PV	59,783	70,980	73,283	75,561	77,594	85,210	89,007	99,630	113,569	127,723	138,322	149,455	159,637	171,887	182,465	196,627	209,406	225,874	240,641	257,229	271,530	285,945	297,510	308,542	319,209	332,063
Wind	71,535	71,595	71,792	71,822	71,637	73,543	78,933	84,933	90,326	95,921	101,427	107,478	112,791	118,053	122,196	122,408	122,171	122,000	122,128	122,000	121,574	122,255	127,766	133,510	132,744	137,279
Wind - Offshore	49	10,806	18,317	20,626	22,763	25,927	28,099	30,283	32,451	35,103	41,332	42,147	46,062	51,704	59,054	63,824	67,435	72,066	76,879	84,237	99,129	101,364	107,369	117,903	127,588	146,639

Figure 3.5 **PJM Expasion Plan with the EPA CAA Section 111 Update, High Fuels, Nameplate Capacity (GW)**

Nameplate Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	3,147	3,902	4,289	4,692	5,072	6,528	6,936	7,377	8,531	8,886	10,624	10,610	11,277	12,004	13,735	14,447	15,284	16,725	16,681	17,863	19,166	20,113	21,383	20,702	21,188	22,041
Coal	35,495	30,415	29,969	27,784	23,746	21,373	18,275	8,644	8,644	7,419	5,769	5,606	5,606	5,606												
Combined Cycle	57,238	57,099	56,929	59,578	60,421	62,312	61,760	63,145	60,878	58,920	57,261	57,497	59,390	59,390	61,974	61,974	61,974	61,974	61,953	61,953	61,953	61,953	61,953	61,953	61,929	60,624
Combustion Turbine	24,742	24,608	24,582	24,132	24,057	23,986	23,270	22,928	22,781	22,781	22,465	22,465	22,465	22,452	22,120	21,784	21,629	20,744	20,667	20,667	20,579	20,340	20,197	20,118	18,857	16,147
Nuclear	32,995	31,730	29,970	29,970	29,970	28,726	27,578	27,578	31,299	30,253	30,261	27,268	26,356	25,165	25,165	24,007	24,007	21,531	21,531	17,864	17,864	16,692	15,755	15,755	14,565	14,565
Other	26,436	26,501	26,616	27,099	27,689	26,389	27,117	28,084	28,607	30,001	31,353	32,594	34,216	36,094	38,134	40,196	42,288	44,481	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	34,610	42,326	48,069	55,257	62,584	70,456	79,907	89,572	99,189	107,773	112,563	117,239	126,719	134,395	143,788	153,134	156,340	165,622	172,000	181,180	190,289	197,211	203,498	212,434	218,501	223,474
Wind	29,572	33,572	37,572	39,819	41,819	44,214	46,214	50,214	52,214	54,214	54,314	56,314	57,572	59,214	60,286	60,803	60,803	63,803	63,915	66,915	68,933	69,404	71,201	73,201	74,905	75,345
Wind - Offshore	12	8,012	14,835	18,835	20,835	22,835	24,835	29,263	29,263	29,263	31,263	33,263	36,317	40,304	44,502	46,502	48,502	50,819	50,819	55,893	58,116	60,201	60,920	62,824	63,227	65,507

Figure 3.6 **PJM Generation with the EPA CAA Section 111 Update, High Fuels, Generation (GWh)**

Generation (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	-668	-871	-971	-1,091	-1,190	-1,555	-1,724	-1,870	-2,280	-2,381	-2,764	-2,699	-2,841	-2,977	-3,431	-3,642	-3,745	-4,117	-4,136	-4,420	-4,716	-4,938	-5,165	-5,090	-5,157	-5,261
Coal	141,000	135,802	132,381	121,803	109,266	75,657	66,681	30,987	27,572	22,688	19,444	18,916	18,192	17,517												
Combined Cycle	270,295	240,214	223,793	215,203	213,068	240,361	236,139	243,037	208,251	199,161	200,712	208,820	208,718	201,695	199,779	192,170	188,344	184,665	186,434	171,556	169,457	164,951	161,608	154,433	149,942	143,098
Combustion Turbine	4,366	2,859	2,541	1,687	1,506	1,679	2,559	2,537	1,254	1,309	1,090	1,209	1,229	985	850	709	598	550	695	525	577	566	472	511	642	478
Nuclear	265,511	258,988	240,382	241,670	242,770	228,987	222,202	222,717	251,354	256,013	247,721	232,265	217,137	206,582	203,533	199,631	197,426	182,491	168,382	150,791	136,052	131,534	124,269	119,071	113,459	109,906
Other	17,228	16,392	15,818	14,456	14,140	13,946	12,437	11,597	10,634	9,988	9,593	8,412	7,969	7,521	6,716	6,127	5,955	4,781	4,395	3,545	3,011	2,352	1,751	564	60	-797
Solar PV	59,799	74,452	85,237	98,382	111,315	125,503	141,832	157,718	173,131	185,878	194,079	202,978	216,891	228,088	240,627	252,649	257,073	269,531	281,244	294,634	307,574	317,049	326,235	336,832	343,601	349,961
Wind	70,679	81,963	93,143	99,491	104,634	111,225	116,487	127,271	131,438	134,665	134,745	141,357	144,167	148,586	150,687	151,973	152,770	160,420	162,932	171,338	176,040	177,126	182,318	187,454	190,855	192,312
Wind - Offshore	49	29,916	56,091	71,239	78,465	85,884	93,369	109,214	109,191	109,445	117,145	124,319	134,789	150,501	166,188	174,387	182,971	191,661	191,692	212,381	220,923	228,989	233,229	239,984	243,401	253,170

Figure 3.7 **PJM Expasion Plan with the EPA CAA Section 111 Update, Low Fuels, Nameplate Capacity (GW)**

Nameplate Capacity (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Battery	3,181	3,986	4,371	4,775	5,154	6,611	7,017	7,923	8,413	8,384	10,124	10,266	10,239	10,230	9,866	9,368	9,155	9,386	9,528	10,035	10,183	10,173	9,731	9,724	9,716	10,416
Coal	34,992	29,349	28,903	26,718	22,680	21,227	16,594	8,644	7,345	5,463	2,067	1,062	1,062	1,062												
Combined Cycle	57,238	58,188	58,018	64,968	69,391	72,688	75,065	79,719	85,560	88,769	91,745	95,833	99,185	98,786	98,871	100,142	99,819	101,025	100,352	101,716	103,080	104,444	105,522	105,522	107,169	107,922
Combustion Turbine	24,742	24,665	24,639	24,189	24,114	24,043	23,932	23,123	22,781	22,781	22,465	22,315	22,181	22,168	21,792	21,456	21,301	20,416	20,290	20,290	20,202	20,113	20,104	20,025	18,808	16,098
H2 CT																				249	249	249	249	249	249	249
Nuclear	32,995	31,730	29,531	29,531	29,531	27,578	27,578	27,578	25,715	23,469	23,469	20,668	19,756	18,565	18,565	17,926	17,926	16,085	16,261	13,064	13,064	11,892	10,955	10,955	9,765	10,308
Other	26,999	26,501	27,163	27,646	28,236	27,816	27,118	28,084	28,607	30,002	31,354	32,595	34,217	36,095	38,135	40,197	42,289	44,482	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	34,610	40,499	41,655	42,827	44,290	48,360	50,277	56,264	61,808	66,933	68,998	72,681	77,310	83,102	88,000	94,546	100,696	109,038	116,943	126,397	135,780	144,116	153,272	161,064	166,018	172,959
Wind	29,572	29,572	29,572	29,572	29,572	29,572	29,572	31,572	31,572	31,572	31,572	31,572	31,572	31,572	31,572	31,572	31,572	32,352	32,352	35,138	37,138	39,138	41,138	43,138	45,138	47,138
Wind - Offshore	12	2794	4652	5249	5840	6743	7321	7926	8474	9064	10726	10743	11592	12229	12738	13169	14070	14200	14952	14952	15759	15759	15759	15759	15759	15780

Figure 3.8 **PJM Generation with the EPA CAA Section 111 Update, Low Fuels, Generation (GWh)**

Generation (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Battery	-682	-903	-977	-1,035	-1,101	-1,435	-1,532	-1,498	-1,632	-1,719	-2,116	-2,164	-2,164
Coal	70,267	77,275	82,213	68,426	56,899	52,502	47,682	32,243	26,013	18,345	8,363	3,554	3,596
Combined Cycle	321,351	318,174	325,462	355,109	374,334	396,607	409,519	416,468	444,320	458,536	478,920	509,499	521,646
Combustion Turbine	25,915	22,348	24,595	17,648	14,164	13,389	12,458	10,383	6,182	5,172	3,516	3,330	3,672
H2 CT													
Nuclear	265,511	258,988	236,780	237,972	239,204	219,253	222,202	222,717	204,716	198,999	190,340	176,083	161,112
Other	22,138	19,581	19,590	17,161	16,614	16,054	13,333	13,436	12,569	12,212	11,892	10,559	10,108
Solar PV	59,780	71,067	73,372	75,646	78,234	85,813	89,513	100,724	111,026	120,345	124,437	131,861	139,939
Wind	71,589	71,738	71,940	72,027	71,910	72,091	71,938	77,825	77,628	77,652	77,658	77,931	77,717
Wind - Offshore	49	10439	17947	20255	22393	25778	27952	30137	32302	34466	40695	41476	44307

Generation (GWh)	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Battery	-2,205	-2,116	-2,040	-1,979	-2,045	-2,073	-2,165	-2,222	-2,198	-2,087	-2,084	-2,062	-2,233
Coal	3,743												
Combined Cycle	525,704	521,643	515,309	509,005	508,630	502,683	492,053	488,733	482,218	476,450	468,539	467,637	451,775
Combustion Turbine	4,407	4,325	2,869	2,510	2,101	2,073	1,500	1,361	854	695	799	455	406
H2 CT							0	0	0	0	0	0	0
Nuclear	150,511	147,464	147,827	145,775	136,216	129,567	118,679	104,176	100,051	92,887	88,744	83,349	84,513
Other	9,842	9,320	8,944	8,613	7,696	7,336	6,919	6,308	5,962	5,268	4,662	4,173	3,485
Solar PV	150,901	160,244	172,234	183,498	198,467	212,284	229,847	245,806	260,912	277,157	291,243	299,177	311,691
Wind	77,645	77,611	77,809	77,685	79,915	79,973	87,973	93,387	98,865	104,417	110,366	115,397	120,947
Wind - Offshore	46926	48896	50675	53944	54442	56947	57433	60230	60191	60551	60615	60982	61316

Figure 3.9 **PJM Expasion Plan Without the EPA CAA Section 111 Update, Base Fuels, Nameplate Capacity (GW)**

Nameplate Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	3,156	3,961	4,347	4,750	5,130	6,586	6,994	7,434	8,475	8,767	10,505	10,493	10,465	10,455	10,105	9,417	9,082	9,449	9,564	9,557	9,550	9,543	9,536	9,126	10,044	11,253
Coal	35,329	29,337	28,891	26,706	22,668	20,385	16,647	12,855	11,794	11,132	9,459	9,296	9,209	9,209	8,941	8,941	7,747	7,167	7,167	7,167	5,831	5,169	3,618	2,968	1,638	288
Combined Cycle	57,238	58,188	58,018	66,178	71,174	73,776	74,880	77,048	79,113	79,995	79,882	80,214	83,155	83,569	83,766	84,130	85,141	85,637	85,750	85,876	86,335	86,551	87,127	87,161	87,410	86,105
Combustion Turbine	24,742	24,665	24,639	24,189	24,114	24,043	23,932	23,932	23,540	23,540	23,540	23,540	23,540	23,527	23,129	22,709	22,239	21,207	20,983	20,983	20,584	20,345	20,202	20,123	18,862	16,152
Nuclear	32,995	31,730	29,531	29,531	29,531	27,578	27,578	27,578	25,007	22,205	23,317	21,268	20,949	20,365	20,365	19,807	19,807	18,570	18,974	17,361	17,864	16,692	15,755	15,755	14,565	14,565
Other	26,609	26,501	27,163	27,646	28,236	27,816	27,118	28,085	28,608	30,003	31,355	32,596	34,218	36,096	38,136	40,198	42,289	44,482	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	34,611	40,448	41,604	42,776	44,311	48,397	50,663	55,735	63,435	70,942	76,614	82,057	90,522	100,134	108,384	117,169	124,924	134,362	142,583	148,860	157,266	163,432	170,800	179,662	188,662	197,450
Wind	29,571	29,571	29,571	29,571	29,571	31,483	33,483	35,483	37,483	39,483	41,483	43,483	45,483	47,483	47,671	47,671	47,671	48,442	48,442	48,451	48,718	49,873	54,045	57,514	59,726	62,291
Wind - Offshore	12	2,883	4,741	5,338	5,929	6,798	7,376	7,981	8,529	9,119	10,781	10,798	10,926	11,565	11,565	11,965	12,659	13,062	14,018	16,018	22,018	27,811	32,038	34,438	40,454	46,215

Figure 3.10 **PJM Generation Without the EPA CAA Section 111 Update, Base Fuels, Generation (GWh)**

Generation (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Battery	-677	-896	-966	-1,023	-1,088	-1,429	-1,529	-1,660	-1,867	-1,985	-2,380	-2,351	-2,360
Coal	88,821	90,470	90,606	73,731	59,261	53,897	47,186	38,422	37,409	32,913	31,010	30,018	29,409
Combined Cycle	311,343	311,028	321,845	354,981	374,839	390,752	397,725	407,444	417,793	420,856	408,051	414,701	414,425
Combustion Turbine	19,403	16,883	20,224	12,375	9,396	9,228	8,279	5,546	3,676	3,126	2,105	1,967	1,358
Nuclear	265,511	258,988	236,780	237,972	239,204	219,253	222,202	222,717	198,707	188,262	189,046	181,197	171,252
Other	20,331	18,745	19,131	16,529	15,997	15,550	13,156	12,413	11,927	11,597	11,340	10,044	9,734
Solar PV	59,782	70,980	73,282	75,562	78,283	85,893	90,215	99,756	113,739	127,232	137,832	148,512	163,152
Wind	71,531	71,557	71,802	71,926	71,801	77,364	82,806	88,675	94,096	99,730	105,265	111,318	116,614
Wind - Offshore	49	10,766	18,279	20,586	22,722	25,986	28,160	30,344	32,510	34,671	40,902	41,715	41,848

Generation (GWh)	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	-2,363	-2,288	-2,127	-2,029	-2,158	-2,169	-2,175	-2,231	-2,266	-2,296	-2,226	-2,473	-2,812
Coal	29,447	28,354	29,752	24,352	22,587	21,707	21,084	16,266	13,931	10,202	8,302	4,353	697
Combined Cycle	405,371	395,742	383,669	379,306	372,950	365,821	350,127	339,133	322,824	306,807	293,215	276,606	253,855
Combustion Turbine	1,201	1,123	655	673	534	536	421	406	332	298	323	161	201
Nuclear	165,800	162,757	163,847	161,748	157,335	152,651	155,343	144,697	140,248	132,539	127,747	121,677	117,502
Other	9,263	8,605	8,100	7,609	6,740	6,280	5,600	4,794	3,947	2,894	1,543	498	-878
Solar PV	180,298	195,262	210,966	224,565	241,234	255,231	266,519	279,062	288,119	299,182	312,446	322,353	332,508
Wind	121,850	122,265	122,529	122,259	124,345	124,467	124,378	124,625	127,354	138,656	148,225	152,857	159,379
Wind - Offshore	44,458	44,492	46,120	48,582	50,103	53,342	61,331	83,531	105,146	120,965	129,986	152,408	174,017

Figure 3.11 **PJM Expasion Plan Without the EPA CAA Section 111 Update,High Fuels, Nameplate Capacity (GW)**

Nameplate Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	3,147	3,902	4,289	4,692	5,072	6,528	6,936	7,377	8,461	8,432	10,172	10,837	11,482	12,141	11,791	12,319	13,804	15,251	15,215	16,733	17,452	18,631	20,220	20,287	21,412	23,272
Coal	35,495	30,404	29,958	27,773	23,735	21,362	19,085	19,085	19,085	19,085	17,149	15,968	15,968	15,968	15,968	15,414	11,434	10,264	10,264	10,264	10,264	8,899	8,099	6,799	5,469	4,119
Combined Cycle	57,238	57,099	56,929	60,220	61,584	62,948	62,519	59,928	56,388	52,177	49,665	49,353	50,635	50,814	50,814	50,937	52,604	54,314	54,314	54,349	54,349	54,950	54,950	54,950	54,925	53,756
Combustion Turbine	24,742	24,608	24,582	24,132	24,057	23,986	23,270	22,928	22,781	22,781	22,465	22,465	22,465	22,452	22,120	21,784	21,629	20,744	20,667	20,667	20,579	20,340	20,197	20,118	18,857	16,147
Nuclear	32,995	31,730	29,970	29,970	29,970	28,726	27,578	27,578	30,718	29,578	29,603	27,268	26,356	25,165	25,165	24,007	24,007	21,531	21,531	17,864	17,864	16,692	15,755	15,755	14,565	14,565
Other	26,423	26,501	26,616	27,099	27,689	26,389	27,117	28,084	28,607	30,001	31,353	32,594	34,216	36,094	38,134	40,196	42,288	44,481	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	34,610	42,326	48,069	55,185	61,632	69,147	78,869	88,539	98,162	104,296	108,787	116,471	125,952	135,388	141,096	149,910	157,429	166,706	174,843	184,009	191,126	198,254	205,855	214,186	220,399	227,484
Wind	29,572	33,572	37,572	39,572	41,572	43,572	45,572	47,572	49,572	51,572	51,672	53,672	55,672	56,572	56,572	58,191	59,655	62,191	62,449	65,359	66,292	67,890	69,905	71,191	73,191	74,806
Wind - Offshore	12	8,012	14,835	18,835	20,835	22,760	22,760	24,760	25,722	25,836	29,244	31,261	35,205	38,145	40,145	43,320	45,522	47,522	49,261	52,863	54,493	57,342	58,307	60,846	62,127	64,259

Figure 3.12 **PJM Generation Without the EPA CAA Section 111 Update, High Fuels, Generation (GWh)**

Generation (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Battery	-669	-870	-970	-1,090	-1,200	-1,578	-1,729	-1,895	-2,260	-2,268	-2,707	-2,807	-2,972	-3,083	-2,999	-3,157	-3,531	-3,869	-3,887	-4,253	-4,447	-4,731	-5,034	-5,162	-5,358	-5,703
Coal	141,065	135,782	132,356	121,284	108,458	90,259	82,846	81,124	78,234	75,722	72,088	66,458	65,641	63,243	64,583	61,922	44,735	38,367	37,770	37,992	35,777	32,076	30,068	24,580	19,029	14,862
Combined Cycle	270,514	240,383	223,887	216,666	215,020	227,090	226,417	212,401	178,430	165,889	162,243	167,138	161,359	157,028	147,860	139,263	144,376	148,832	146,736	137,234	140,630	137,023	133,365	130,803	129,849	123,407
Combustion Turbine	4,391	2,874	2,548	1,558	1,205	1,291	1,873	1,557	1,058	1,339	1,211	1,326	1,274	1,025	875	790	770	592	673	508	617	591	529	542	663	492
Nuclear	265,511	258,988	240,382	241,670	242,770	228,987	222,202	222,717	246,740	250,553	242,220	232,273	217,176	206,583	203,533	199,631	197,426	182,491	169,530	152,547	137,612	132,321	124,854	119,757	113,985	110,051
Other	17,218	16,400	15,821	14,450	14,139	13,848	12,414	11,495	10,607	9,989	9,585	8,283	7,714	7,325	6,650	5,893	5,544	4,450	3,875	2,923	2,476	1,633	816	-477	-1,044	-1,960
Solar PV	59,799	74,453	85,235	98,254	109,716	123,412	140,474	157,211	172,825	182,378	190,164	204,312	217,992	232,636	240,854	251,875	262,156	274,804	288,109	301,997	312,710	321,490	332,057	341,582	348,367	357,267
Wind	70,688	81,950	93,136	98,804	103,949	109,649	115,039	120,700	125,121	129,328	129,549	135,579	140,381	142,655	142,552	146,853	150,958	157,397	159,459	167,659	169,722	174,009	179,522	183,130	187,026	190,683
Wind - Offshore	49	29,916	56,092	71,243	78,484	85,579	85,613	92,758	96,383	96,911	109,803	117,302	131,075	143,314	151,786	164,124	172,296	180,566	186,420	201,553	207,772	218,952	223,642	232,746	238,740	248,016

Figure 3.13 PJM Expasion Plan Without the EPA CAA Section 111 Update, Low Fuels, Nameplate Capacity (GW)

Nameplate Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	3,179	3,984	4,369	4,772	5,152	6,608	7,015	7,456	8,496	8,777	10,513	10,503	10,475	10,464	10,092	9,726	9,578	9,704	9,697	9,873	9,865	9,857	9,849	9,329	9,202	9,921
Coal	34,981	29,338	28,892	26,707	22,669	21,219	17,482	13,635	11,630	9,180	7,585	7,422	7,311	4,598	2,643	2,343	580									
Combined Cycle	57,238	58,188	58,018	66,179	70,322	73,199	74,552	77,852	81,178	85,640	88,260	90,347	94,602	98,036	98,150	98,189	99,019	99,132	99,174	99,174	98,952	96,018	94,976	94,748	94,723	92,430
Combustion Turbine	24,742	24,665	24,639	24,189	24,114	24,043	23,932	23,932	23,875	23,875	23,875	23,875	23,875	23,862	23,402	22,904	22,239	21,207	20,983	20,983	20,584	20,345	20,202	20,123	18,862	16,152
Nuclear	32,995	31,730	29,531	29,531	29,531	27,578	27,578	27,578	25,007	21,861	21,861	18,868	17,956	17,365	19,165	19,077	19,207	17,331	17,331	14,340	15,596	16,692	15,755	15,755	14,565	14,565
Other	26,999	26,501	27,163	27,646	28,236	27,816	27,118	28,085	28,608	30,003	31,355	32,596	34,218	36,096	38,136	40,198	42,289	44,482	46,860	49,276	51,880	54,878	57,632	60,326	62,977	65,460
Solar PV	34,610	40,508	41,664	42,837	44,301	48,371	50,487	52,806	59,890	66,276	71,496	76,164	82,009	88,654	95,702	104,749	114,195	123,687	133,130	142,506	150,127	157,290	166,336	174,862	183,889	192,699
Wind	29,572	29,572	29,572	29,572	29,572	29,572	29,572	29,572	29,572	29,572	29,572	29,572	30,055	32,607	34,607	36,607	38,607	41,432	43,432	45,432	47,432	49,432	50,854	50,854	52,854	58,854
Wind - Offshore	12	2,789	4,647	5,244	5,835	6,801	7,379	7,984	8,532	9,122	10,784	10,801	10,817	11,058	11,058	11,058	11,491	11,491	12,404	13,481	15,523	21,523	27,523	30,764	38,006	46,006

Figure 3.14 **PJM Generation Without the EPA CAA Section 111 Update, Low Fuels, Generation (GWh)**

Generation (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Battery	-682	-902	-977	-1,044	-1,108	-1,433	-1,539	-1,652	-1,852	-1,969	-2,397	-2,377	-2,376	-2,363	-2,245	-2,181	-2,151	-2,222	-2,195	-2,250	-2,284	-2,344	-2,382	-2,277	-2,286	-2,613
Coal	70,345	77,320	82,229	65,857	54,608	51,099	49,004	37,178	32,495	19,332	15,798	14,288	13,353	7,811	5,295	4,648	502									
Combined Cycle	321,514	318,266	325,517	360,028	375,215	394,407	403,388	427,127	447,056	472,112	479,014	501,008	515,094	518,951	495,582	477,203	464,671	458,483	446,425	432,361	418,729	380,451	357,888	346,886	323,060	285,978
Combustion Turbine	25,935	22,378	24,592	16,096	12,632	12,194	10,845	7,858	5,968	5,174	3,842	3,934	3,000	2,439	1,546	787	752	712	620	707	606	351	319	315	156	237
Nuclear	265,511	258,988	236,780	237,972	239,204	219,253	222,202	222,717	198,707	185,343	176,684	160,748	145,817	140,314	152,563	157,623	156,653	146,807	138,692	129,652	125,782	141,013	133,887	129,500	123,101	117,920
Other	22,145	19,591	19,598	16,981	16,406	15,908	13,205	12,499	11,920	11,556	11,251	9,989	9,726	9,310	8,836	8,249	7,788	6,905	6,402	5,797	4,952	4,051	2,952	1,764	324	-1,502
Solar PV	59,780	71,085	73,389	75,661	78,253	85,832	89,874	94,345	107,224	118,776	128,611	137,892	148,036	160,179	173,200	189,545	206,447	223,319	239,740	256,817	269,173	280,151	293,940	307,259	317,125	326,435
Wind	71,580	71,723	71,929	72,005	71,952	72,115	72,037	72,204	72,075	72,096	72,098	72,328	73,581	80,727	86,302	92,026	97,357	105,142	110,874	116,372	121,680	126,643	130,348	130,502	134,293	149,438
Wind - Offshore	49	10,417	17,930	20,237	22,374	25,996	28,170	30,353	32,518	34,683	40,910	41,693	41,411	42,535	42,584	42,760	44,281	44,260	47,425	51,875	59,294	81,714	104,053	116,073	142,996	172,322

Figure 3.15 PJM Power Prices with the EPA CAA Section 111 Update - Average of Power Prices ($/MWh)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
High Fuels	$53.69	$58.05	$57.85	$57.52	$57.06	$58.29	$59.30	$61.24	$57.04	$56.48	$58.67	$60.42	$60.65
Base Fuels	$43.16	$45.34	$45.95	$44.28	$43.59	$44.58	$45.28	$48.95	$47.36	$46.09	$45.98	$46.72	$48.00
Low Fuels	$38.91	$40.97	$41.58	$40.41	$39.83	$40.88	$41.90	$45.95	$44.33	$42.23	$41.50	$40.23	$39.97

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
High Fuels	$61.13	$62.52	$61.80	$63.30	$63.03	$65.02	$66.98	$67.55	$68.85	$71.66	$71.87	$74.22	$76.41
Base Fuels	$49.69	$49.86	$51.23	$52.99	$53.49	$54.33	$55.94	$56.93	$58.15	$60.39	$61.70	$63.46	$66.00
Low Fuels	$41.36	$42.70	$43.00	$44.30	$45.04	$46.15	$47.34	$47.95	$48.56	$50.38	$52.17	$53.38	$54.31

Figure 3.16 **PJM Power Prices Without the EPA CAA Section 111 Update - Average of Power Prices ($/MWh)**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
High Fuels	$53.72	$58.08	$57.87	$57.38	$56.52	$56.32	$57.04	$58.31	$56.01	$56.49	$58.46	$59.89	$59.97
Base Fuels	$43.17	$45.36	$45.96	$44.79	$43.68	$44.23	$44.89	$45.29	$46.35	$46.77	$47.86	$48.73	$49.14
Low Fuels	$38.92	$40.99	$41.58	$40.24	$39.59	$40.51	$41.23	$42.35	$43.23	$41.63	$41.17	$41.73	$41.49

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
High Fuels	$60.34	$62.11	$61.24	$62.16	$62.11	$63.09	$64.45	$65.76	$66.51	$68.46	$69.35	$71.61	$72.32
Base Fuels	$50.35	$51.05	$51.77	$53.43	$53.63	$54.37	$54.72	$55.27	$55.72	$56.75	$57.00	$57.02	$58.51
Low Fuels	$40.76	$41.31	$41.05	$41.49	$41.25	$41.73	$42.41	$41.45	$40.16	$41.19	$41.97	$41.90	$41.71

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-007

REQUEST:

Refer to the IRP, page 16.

a. Explain in detail how the energy prices derived from the generation expansion plans for the entire Eastern Interconnect from Central Canada eastward to the Atlantic Coast, south the Florida and west to the foot of the Rockies is used to simulate PJM energy prices in Duke Energy Ohio Kentucky (DEOK) Zone.

b. Explain how the Base, High, and Low Fuel prices were obtained or derived with and without EPA CAA Section 111 updates across the entire Eastern Interconnect.

RESPONSE:

a. In modeling the generation expansion plan for the entire eastern interconnect, the zonal pricing in each of the defined areas within the eastern interconnect is developed from the subsequent production cost run. The model captures local requirements for reserve margin and ancillary services while also accounting for transmission limits between zones. This results in a power price for PJM-Cin-KY that accounts for the interactions of this localized market with the larger RTO and Eastern Interconnect. Once an hourly power price projection is determined the values are calibrated to the projected short term market prices for PJM.

b. Fuel prices do not vary with and without 111. Base fuel prices are based off a combination of market data and fundamental fuel price data averaged from projections gathered from four different sources. The first 5 years of the forecast are based on market data, the following three years are a blend starting from 100% market prices and 0% fundamental prices steadily changing to 100% fundamental and 0% market prices by the end of the 3 years, with all subsequent pricing being 100% fundamental from the 4 different sources (U.S. Energy Information Administration (EIA), Energy Ventures Analysis (EVA), S&P Global, Wood Mackenzie). The high and low forecasts are based on EIA Annual Energy Outlook (AEO) report Reference, High Oil/Gas Supply, and Low Oil/Gas Supply cases. The differences from base to the EIA AEO high and low cases are turned into scalars which are applied to the natural gas and coal prices in the model.

PERSON RESPONSIBLE: Tyler Cook

STAFF-DR-01-008

REQUEST:

Refer to the IRP, page 28. Define "energy community."

RESPONSE:

Energy community is defined in 25 USC 45 (b) (11) (B):

> (B) Energy community. For purposes of this paragraph, the term "energy community" means—
>
> > (i) a brownfield site (as defined in subparagraphs (A), (B), and (D)(ii)(III) of section 101(39) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 U.S.C. 9601(39))),
> >
> > (ii) a metropolitan statistical area or non-metropolitan statistical area which—
> >
> > > (I) has (or, at any time during the period beginning after December 31, 2009, had) 0.17 percent or greater direct employment or 25 percent or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas (as determined by the Secretary), and
> > >
> > > (II)has an unemployment rate at or above the national average unemployment rate for the previous year (as determined by the Secretary), or

(iii) a census tract—

(I) in which—

(aa) after December 31, 1999, a coal mine has closed, or

(bb) after December 31, 2009, a coal-fired electric generating unit has been retired, or

(II) which is directly adjoining to any census tract described in subclause (I).

PERSON RESPONSIBLE: Jennifer Poppler
Matt Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-009

REQUEST:

Refer to IRP at 33, Table 4.1.

a. State whether the Summer Capacity MW values in Table 4.1 were used by the model as maximums or fixed values.

b. Explain how the Summer Capacity MW values in Table 4.1 were determined.

RESPONSE:

a. The Summer Capacity MW values in Table 4.1 are max capacity values, apart from wind, solar and battery storage. Wind, solar and battery storage need to be corrected to show summer max capacity. The corrected values are: wind – 150 MW, solar PV, single axis tracking – 100 MW, and battery storage, 4-hour, lithium-ion – 50MW/200 MWh. Those are the corrected values for which the model based the resource project size.

b. The Summer Capacity MW values in Table 4.1 were provided by the Generic Unit Summary, which is developed internally twice annually with support from third parties and internal experts.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-010

REQUEST:

Refer to the IRP, Table 4.1 page 33. Small modular nuclear reactors (SMRs) and carbon capture and sequestration (CCS) are not quite market ready yet. Explain whether the EnCompass model was constrained as to when a particular resource could be constructed and added to the generation portfolio. If so, explain which resources and the dates they could be included in the generation portfolio.

RESPONSE:

Small modular nuclear reactors (SMRs) and carbon capture and sequestration (CCS) were both constrained in the EnCompass model due to their market readiness. SMRs could be added to the generation portfolio beginning in 2038 and CCS projects beginning 2035.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-011

REQUEST:

Refer to the IRP, Table 4.1 page 33 and 35.

a. Explain the basis for the summer capacity ratings for each of the resources, i.e., nameplate, unforced capacity, PJM accreditation, etc. If PJM accreditation is the basis, explain the corresponding PJM Delivery Year.

b. Provide an update to Table 4.1 to include Duke Kentucky's existing resources (listed on page 35) and showing capacity values at summer and winter peak, and at summer and winter peak on an Effective Load Carrying Capability (ELCC) basis.

c. Explain how each of the resources listed in Table 4.1 including Duke Kentucky's existing resources, are represented, and evaluated in the EnCompass resource optimization/selection process and in the Portfolio analysis process.

d. For each of the potential resources offered into the EnCompass model including Duke Kentucky's existing resources, provide and explain the useful lives of the resources used in the modeling, regardless of when the resource was included in a portfolio. For example, if the useful life of a resource is 40 years that was added to a portfolio in year 10 of the IRP study period, confirm that 40 years would be used and not a lesser amount so as to skew the production cost analysis.

RESPONSE:

a. The basis for summer capacity in Table 4.1 should be nameplate capacity. This is true for all but Wind, Solar PV and Battery Storage which should be 150MW, 100MW, and 100MW, respectively.

b. See table below. Values for existing resources are based on class averages.

	Max Capacity (MW)		ELCC PJM 25-26 (MW)	
Resource Type	Summer	Winter	Summer	Winter
Nuclear Small Modular Reactor	300	300	288	288
Combined Cycle Gas Turbine 2x1	1282	1364	1012.78	1077.56
Combined Cycle Gas Turbine, 1x1	636	664	502.44	524.56
Combined Cycle Gas Turbine with CCS, 1x1	535	588	422.65	464.52
Simple Cycle Gas Turbine	791	851	624.89	672.29
Wind	150	150	52.5	52.5
Solar PV, Single Axis Tracking	100	100	14	14
Battery Storage, 4-hr Lithium-Ion	100	100	59	59
Existing Coal	600	600	504	504
Existing Simple Cycle Gas Turbines	476	564	376.04	445.56
Existing Solar PV	9	9	0.81	0.81
Existing Demand Response	24	24	18.48	18.48

c. Resources in EnCompass are represented by a series of inputs that are used to define the operating characteristics of a unit. The characteristics and cost for existing units are drawn from testing and historical data, while for new units it is based on the capabilities and costs of generic units that are sourced from consultants. The model than determines the lowest cost solution to meet the required load and reserve margin by comparing operation of existing resources to PJM market power prices, and the cost of constructing and operating new resources.

d. In production cost analysis only costs within the study period are reported, so for a resource added 10 years prior to the end of the study period with a 40 year book/operating life you would see levelized capital costs from the first 10 years of operation reported in a production cost run. See table below for the assumed operating life for each resource.

Resource Type	Operating Life (years)
Nuclear Small Modular Reactor	60
Combined Cycle Gas Turbine 2x1	35
Combined Cycle Gas Turbine, 1x1	35
Combined Cycle Gas Turbine with CCS, 1x1	35
Simple Cycle Gas Turbine	35
Wind	30
Solar PV, Single Axis Tracking	30
Battery Storage, 4-hr Lithium-Ion	30
Existing Coal	-
Existing Simple Cycle Gas Turbines	-
Existing Solar PV	-
Existing Demand Response	-

PERSON RESPONSIBLE: Tyler Cook

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-012

REQUEST:

Refer to the IRP, Table 4.1 page 33 and 37.

a. Explain why a 100 MW nameplate 4-hour Lithium-Ion battery is only credited with 16 MW at summer peak but has a 2025/2026 BRA ELCC Class Rating of 59 percent.

b. Explain whether the 4-hour Lithium-Ion battery was modeled as being able to provide capacity, energy, and ancillary services in order to realize its full potential relative to other potential resources.

RESPONSE:

a. This was a mistake in Table 4.1. The Summer Capacity (MW) column for "Battery Storage, 4-hour Lithium-ion" should have been 100 MW. The firm capacity for the Battery Storage is based on 2025/2026 BRA ELCC Class rating of 59% or 59 MW. This is included in the modeling correctly.

b. Yes, the 4-hr Lithium-Ion battery was modeled as being able to provide capacity, energy, and ancillary services.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-013

REQUEST:

Refer to the IRP, page 37. Explain the extent to which Duke Kentucky has studied the feasibility of installing CCS at East Bend.

RESPONSE:

The only study that was conducted at East Bend was part of a National Energy Technology Laboratory project (available at: https://netl.doe.gov/coal/carbon-storage/atlas/mrcsp/phase-II/cincinnati-arch) which found "The Mt. Simon Sandstone was a very effective CO2 storage zone at the East Bend site. The CO2 was trucked in for the injection test and could not be supplied fast enough to keep up with injection. Consequently, the field crew had to wait for more CO2 to be delivered before finishing the injection test. Conducting a brine injection test prior to injecting CO2 was found to be a useful indicator of the ability of the formation to accept large-scale CO2. In this test, injecting CO2 resulted in much lower bottom-hole pressures than injecting a similar amount of brine. This was the first injection of CO2 into the Mt. Simon Sandstone, which is also the storage zone for large-scale and commercial-scale projects in Illinois."

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-014

REQUEST:

Refer to the IRP, page 39. Explain whether has conducted or is aware of wind studies showing that there is sufficient and sustained wind within the Duke Energy Ohio Kentucky (DEOK) PJM Load Zone to justify constructing wind generation.

RESPONSE:

The company has not commissioned a wind resource study specific to the DEOK PJM Load Zone. Wind profiles are generated for the DEOK PJM Load Zone based on historical ERA-5 wind speed data to support IRP modeling. Any detailed Load Zone study or development specific study will need to consider wind speed data from multiple resources.

PERSON RESPONSIBLE: Matthew Ruscio

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-015

REQUEST:

Refer to the IRP, Table 4.1 page 33 and 6.3 page 44.

a. Explain the differences between Solar + Storage: Solar and Solar + Storage: Battery.

b. Provide cost and operational characteristics of these two resource mixes and compare them to all the other potential resources made available to the EnCompass model.

RESPONSE:

a. Solar + Storage: Solar is the solar portion of a Solar + Storage project and Solar + Storage: Storage is the storage portion of a Solar + Storage project. Referring to Table 6.3, in 2028 210 MW of solar and 75 MW of storage were added, this consists of a total of three Solar + Storage projects. Each Solar + Storage project consists of 70 MW of solar with a 1.4 DC/AC inverter ratio and a 25 MW storage component.

b. Please refer to previous response, STAFF-DR-01-005(a).

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-016

REQUEST:

Refer to IRP, pages 43-49, Tables 6.1 to 6.17. Provide estimated capital and operations and maintenance (O&M) cost for each of the portfolios displayed in Tables 6.1 through 6.17.

RESPONSE:

For Tables 6.1 to 6.17, estimated capital and O&M costs for each portfolio through the planning period are provided below.

Capital includes Capital Expenses + AFUDC for new units along with Capital Expenses for existing units.

O&M includes Variable O&M, Fixed O&M, for both new and existing units along with any additional costs related to Dual Fuel or Natural Gas Conversion at East Bend Unit 2 including conversion and firm gas transportation costs.

Costs shown are represented in 2024 dollars on a PVRR basis using a discount rate of 7.29%.

Table 6.1: With EPA CAA Section 111 Update: East Bend DFO Conversion by 2030

Capital ($000)	995,581
O&M ($000)	830,899

Table 6.2: With EPA CAA Section 111 Update - East Bend Natural Gas Conversion by 2030

Capital ($000)	356,742
O&M ($000)	735,925

Table 6.3: With EPA CAA Section 111 Update - East Bend Retirement by 2032

Capital ($000)	1,401,672
O&M ($000)	633,066

Table 6.4: Without EPA CAA Section 111 Update - East Bend DFO Conversion by 2030

Capital ($000)	1,022,924
O&M ($000)	869,152

Table 6.5: Without EPA CAA Section 111 Update - East Bend Natural Gas Conversion by 2030

Capital ($000)	362,428
O&M ($000)	723,943

Table 6.6: Without EPA CAA Section 111 Update - East Bend Retirement by 2036

Capital ($000)	1,144,475
O&M ($000)	763,362

Table 6.7: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039

Capital ($000)	957,204
O&M ($000)	780,214

Table 6.8: With EPA CAA Section 111 Update – East Bend DFO Conversion with SMR Replacement by 2039

Capital ($000)	1,964,967
O&M ($000)	778,492

Table 6.9: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC with CCS Replacement by 2036

Capital ($000)	1,010,901
O&M ($000)	817,198

Table 6.10: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables

Capital ($000)	1,083,765
O&M ($000)	803,722

Table 6.11: With EPA CAA Section 111 Update – East Bend Retires by 2032 with CC Replacement

Capital ($000)	1,163,831
O&M ($000)	678,915

Table 6.12: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039

Capital ($000)	784,884
O&M ($000)	815,601

Table 6.13: Without EPA CAA Section 111 Update – East Bend DFO Conversion with SMR Replacement by 2039

Capital ($000)	1,990,405
O&M ($000)	813,444

Table 6.14: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2036

Capital ($000)	845,438
O&M ($000)	780,345

Table 6.15: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables

Capital ($000)	1,108,535
O&M ($000)	841,869

Table 6.16: Without EPA CAA Section 111 Update – East Bend Retires by 2036 with Accelerated Renewables

Capital ($000)	1,165,740
O&M ($000)	690,212

Table 6.17: Without EPA CAA Section 111 Update – East Bend Retires by 2042

Capital ($000)	289,751
O&M ($000)	289,751

PERSON RESPONSIBLE: **Matthew Kalemba**

STAFF-DR-01-017

REQUEST:

Refer to the IRP, Tables 6.1-6.17 pages 43-49. For each of the tables, provide the requirements of the Clean Air Act (CAA) Section 111 which are being applied to the optimization, how each portfolio satisfies specific applicable CAA Section 111 requirements, both with and without respectively, over the portfolio planning horizon.

RESPONSE:

Table	CAA Section 111 Requirements[1]	How Requirements Are Satisfied
6.1	Yes	EB converted to 40% gas co-firing by 2030 and replaced with a combined cycle fitted with CCS (CC w/ CCS) by 2039
6.2	Yes	EB converted to 100% gas firing by 2030 and replaced with advanced class CTs operating < 40% CF and standalone storage in 2045.
6.3	Yes	EB retired in 2032 and replaced with advanced class CTs operating < 40% CF, solar paired with storage and standalone storage.
6.4	No	Modeled without EPA 111 constraint, however, this portfolio would be compliant with EPA 111 because EB converted to 40% gas co-firing by 2030 and replaced with a combined cycle fitted with CCS (CC w/ CCS) by 2039
6.5	No	Modeled without EPA 111 constraint, however, this portfolio would be compliant with EPA 111 because EB converted to 100% gas firing by 2030 and replaced with advanced class CTs operating < 40% CF and standalone storage in 2045
6.6	No	Modeled without EPA 111 constraint. Portfolio *would not be compliant* with EPA 111 because coal is operated beyond 2032.
6.7	Yes	EB converted to 40% gas co-firing by 2030 and replaced with a combined cycle limited to 40% CF by 2039
6.8	Yes	EB converted to 40% gas co-firing by 2030 and replaced with an advanced class CT operating < 40% CF and an SMR
6.9	Yes	EB converted to 40% gas co-firing by 2030 and replaced with a combined cycle fitted with CCS (CC w/ CCS) in 2036
6.10	Yes	EB converted to 40% gas co-firing by 2030 and replaced with a combined cycle limited to 40% CF by 2039

6.11	Yes	EB retired in 2032 and replaced with CC operating < 40% CF
6.12	No	Modeled without EPA 111 constraint. This portfolio *would not be compliant* with EPA 111 because EB replacement CC in 2039 operates *greater than* 40% CF.
6.13	No	Modeled without EPA 111 constraint, however, this portfolio would be compliant with EPA 111 because EB converted to 40% gas co-firing by 2030 and replaced with an SMR by 2039 and CTs operating < 40% CF
6.14	No	Modeled without EPA 111 constraint. This portfolio *would not be compliant* with EPA 111 because EB replacement CC in 2036 operates *greater than* 40% CF.
6.15	No	Modeled without EPA 111 constraint. This portfolio *would not be compliant* with EPA 111 because EB replacement CC in 2039 operates *greater than* 40% CF.
6.16	No	Modeled without EPA 111 constraint. This portfolio *would not be compliant* with EPA 111 because EB operates on 100% coal beyond 2032 and replacement CC in 2036 operates *greater than* 40% CF
6.17	No	Modeled without EPA 111 constraint. This portfolio *would not be compliant* with EPA 111 because EB operates on 100% coal beyond 2032

Notes:

1 – “Yes” signifies that the portfolio was developed to meet the requirements of CAA Section 111 Update. For existing coal, which means the unit must be 1) retired by 2032 or 2) converted to 40% gas co-firing by 2030 and retired by 2039 or 3) converted to 100% natural gas by 2030. New gas must operate at 40% capacity factor or be fitted with carbon capture and sequestration (CCS) by 2032. “No” signifies the portfolio was developed assuming CAA Section 111 Update was not in place.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-018

REQUEST:

Refer to the IRP, Figures 6.1-6.4, pages 49–51. Provide the data represented by each of the figures (including the data used to calculate the percentages) in excel format with all cells visible and unprotected.

RESPONSE:

Please see Staff-DR-01-018 Attachment.

PERSON RESPONSIBLE: Matthew Peterson

Figure 6.1: PVRR ($000) – Optimized With EPA CAA Section 111 Update

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
111 Scenario with DFO Conversion 2030	$428,770	$682,472	$836,887	$1,016,609	$1,161,348	$1,382,253	$1,525,929	$1,671,248	$1,819,598	$1,941,789	$2,098,688	$2,210,290	$2,315,144	$2,416,049	$2,513,104	$2,607,470
111 Scenario 100% Natural Gas Conversion	$434,243	$686,442	$842,092	$1,012,347	$1,151,343	$1,414,565	$1,568,787	$1,723,904	$1,863,774	$1,991,231	$2,111,164	$2,226,133	$2,333,665	$2,437,780	$2,536,799	$2,629,362
111 Scenario East Bend 2 Retires 2032	$437,159	$692,098	$844,891	$999,793	$1,143,210	$1,274,498	$1,394,261	$1,564,294	$1,716,882	$1,857,487	$1,998,876	$2,133,209	$2,260,387	$2,384,423	$2,503,446	$2,617,958

Figure 6.2: PVRR ($000) – Alternate With EPA CAA Section 111 Update

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alternate - East Bend DFO Conversion with CC Replacement by 2039	$429,597	$685,284	$839,140	$1,013,094	$1,161,784	$1,380,732	$1,525,743	$1,670,723	$1,814,728	$1,937,920	$2,094,268	$2,204,997	$2,309,435	$2,410,783	$2,541,262	$2,666,800
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	$431,005	$688,116	$845,384	$1,023,695	$1,168,541	$1,389,173	$1,535,627	$1,679,261	$1,824,699	$1,946,541	$2,103,150	$2,213,904	$2,318,544	$2,419,059	$2,551,898	$2,677,079
Alternate - East Bend DFO Conversion with CC w/CCS Replacement by 2036	$430,913	$686,586	$843,779	$1,023,251	$1,167,305	$1,388,898	$1,529,254	$1,670,953	$1,799,626	$1,919,418	$2,032,707	$2,139,326	$2,241,513	$2,340,215	$2,436,857	$2,531,656
Preferred - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	$428,110	$682,650	$839,986	$1,019,377	$1,165,073	$1,386,098	$1,533,601	$1,677,274	$1,823,026	$1,944,357	$2,099,035	$2,208,625	$2,311,145	$2,410,064	$2,542,056	$2,669,028
Alternate - East Bend Retirement by 2032 with CC Replacement	$438,892	$694,181	$844,862	$998,123	$1,139,161	$1,272,402	$1,389,643	$1,577,035	$1,750,388	$1,912,327	$2,069,209	$2,217,898	$2,360,159	$2,497,536	$2,627,770	$2,753,472

Figure 6.3: PVRR ($000)– Optimized Without EPA CAA Section 111 Update

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Optimized - East Bend DFO Conversion by 2030	$437,832	$692,635	$846,287	$1,033,048	$1,178,092	$1,390,615	$1,527,912	$1,656,593	$1,801,383	$1,910,102	$2,057,304	$2,158,636	$2,254,561	$2,346,055	$2,443,731	$2,538,210
Optimized - East Bend Natural Gas Conversion by 2030	$423,507	$665,697	$820,149	$986,935	$1,122,104	$1,387,964	$1,543,996	$1,694,832	$1,832,129	$1,962,336	$2,086,597	$2,205,584	$2,315,514	$2,420,957	$2,521,732	$2,615,565
Optimized - East Bend Retirement by 2036	$444,428	$700,519	$856,741	$1,042,448	$1,190,357	$1,326,973	$1,447,553	$1,563,267	$1,675,638	$1,776,696	$1,871,601	$1,978,480	$2,081,565	$2,180,987	$2,277,358	$2,372,750

Figure 6.4: PVRR ($000) – Alternate Without EPA CAA Section 111 Update

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alternate - East Bend DFO Conversion with CC Replacement by 2039	$434,568	$690,357	$845,817	$1,019,530	$1,178,911	$1,388,786	$1,524,869	$1,656,635	$1,793,672	$1,913,857	$2,059,268	$2,161,094	$2,256,106	$2,346,178	$2,471,064	$2,592,348
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	$434,166	$689,714	$843,972	$1,031,473	$1,175,554	$1,387,527	$1,522,284	$1,655,529	$1,801,789	$1,910,862	$2,058,724	$2,160,923	$2,256,387	$2,347,799	$2,481,513	$2,607,257
Alternate - East Bend DFO Conversion with CC Replacement by 2036	$434,699	$687,874	$842,817	$1,028,640	$1,174,975	$1,387,606	$1,518,308	$1,647,118	$1,768,324	$1,877,040	$1,979,252	$2,120,055	$2,255,326	$2,385,881	$2,509,838	$2,631,238
Alternate - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewable	$434,178	$689,291	$844,123	$1,030,013	$1,175,838	$1,390,056	$1,526,266	$1,662,002	$1,806,197	$1,915,239	$2,060,780	$2,161,748	$2,254,842	$2,344,572	$2,469,879	$2,591,630
Preferred - East Bend Retirement by 2036 and Accelerated Renewables	$441,203	$696,345	$852,149	$1,036,663	$1,182,363	$1,320,034	$1,441,682	$1,557,686	$1,669,158	$1,768,810	$1,862,498	$2,001,995	$2,136,360	$2,266,078	$2,390,562	$2,512,128
Alternate - East Bend Retirement by 2042	$439,817	$696,333	$853,258	$1,036,792	$1,184,576	$1,322,440	$1,450,052	$1,568,808	$1,705,769	$1,813,735	$1,953,645	$2,099,734	$2,188,581	$2,280,273	$2,363,210	$2,442,222

STAFF-DR-01-019

REQUEST:

Refer to the IRP, Figures 6.5-6.8, pages 51–53. Provide the data supporting each of the figures (including the data used to calculate the percentages) in excel format with all cells visible and unprotected.

RESPONSE:

Please see STAFF-DR-01-019 Attachment.

PERSON RESPONSIBLE: Matthew Peterson

Figure 6.5: CO2 Reduction – Optimized with EPA CAA Section 111 Update

2005 Base (000 tons)
4,912

Annual CO2 Emissions (000 tons)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	3,397	3,906	4,327	4,188	4,014	3,202	3,068	3,391	2,920	2,542	1,980	1,819	1,933	2,011	188	178
Optimized - East Bend Natural Gas Conversion by 2030	3,281	4,011	4,365	4,181	4,019	2,382	2,272	2,366	1,432	1,190	1,005	978	944	964	876	769
Optimized - East Bend Retirement by 2032	3,420	4,000	4,362	4,171	4,061	4,174	4,076	1,482	1,292	1,175	990	1,003	920	897	781	688

CO2 Reduction From 2005 (%)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	31.0%	20.0%	12.0%	15.0%	18.0%	35.0%	38.0%	31.0%	41.0%	48.0%	60.0%	63.0%	61.0%	59.0%	96.0%	96.0%
Optimized - East Bend Natural Gas Conversion by 2030	33.2%	18.3%	11.1%	14.9%	18.2%	51.5%	53.7%	51.8%	70.9%	75.8%	79.5%	80.1%	80.8%	80.4%	82.2%	84.4%
Optimized - East Bend Retirement by 2032	30.4%	18.6%	11.2%	15.1%	17.3%	15.0%	17.0%	69.8%	73.7%	76.1%	79.9%	79.6%	81.3%	81.7%	84.1%	86.0%

Figure 6.6: CO2 Reduction – Alternate with EPA CAA Section 111 Update

2005 Base (000 tons)
4,912

Annual CO2 Emissions (000 tons)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	3,253	3,889	4,323	4,125	4,010	3,204	3,053	3,398	2,949	2,549	1,858	2,091	2,041	1,801	1,268	1,264
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	3,205	3,878	4,344	4,156	4,019	3,145	3,096	3,377	2,987	2,542	1,958	2,040	1,859	1,829	413	357
Alternate - East Bend DFO Conversion with CC w/CCS Replacement by 2036	3,249	3,920	4,315	4,149	4,045	3,182	3,090	3,390	2,889	2,440	1,953	186	192	193	188	181
Preferred - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	3,419	3,941	4,350	4,149	3,997	3,178	3,032	3,371	2,924	2,527	1,958	1,794	1,798	1,864	1,256	1,246
Alternate - East Bend Retirement by 2032 with CC Replacement	3,398	4,014	4,362	4,137	4,038	4,114	4,038	1,528	1,369	1,344	1,356	1,334	1,310	1,299	1,272	1,261

CO2 Reduction From 2005 (%)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	33.8%	20.8%	12.0%	16.0%	18.4%	34.8%	37.8%	30.8%	40.0%	48.1%	62.2%	57.4%	58.5%	63.3%	74.2%	74.3%
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	34.8%	21.0%	11.6%	15.4%	18.2%	36.0%	37.0%	31.3%	39.2%	48.2%	60.1%	58.5%	62.1%	62.8%	91.6%	92.7%
Alternate - East Bend DFO Conversion with CC w/CCS Replacement by 2036	33.8%	20.2%	12.2%	15.5%	17.7%	35.2%	37.1%	31.0%	41.2%	50.3%	60.2%	96.2%	96.1%	96.1%	96.2%	96.3%
Preferred - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	30.4%	19.8%	11.4%	15.5%	18.6%	35.3%	38.3%	31.4%	40.5%	48.6%	60.1%	63.5%	63.4%	62.1%	74.4%	74.6%
Alternate - East Bend Retirement by 2032 with CC Replacement	30.8%	18.3%	11.2%	15.8%	17.8%	16.2%	17.8%	68.9%	72.1%	72.6%	72.4%	72.8%	73.3%	73.5%	74.1%	74.3%

Figure 6.7: CO2 Reduction – Optimized without EPA CAA Section 111 Update

2005 Base (000 tons)
4,912

Annual CO2 Emissions (000 tons)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	3,373	3,910	4,310	4,180	3,983	4,126	4,063	4,108	3,978	3,965	3,867	3,952	3,818	3,868	191	178
Optimized - East Bend Natural Gas Conversion by 2030	3,688	4,180	4,353	4,236	4,100	2,215	2,004	1,614	1,254	1,087	1,005	959	937	856	839	778
Optimized - East Bend Retirement by 2032	3,326	4,003	4,364	4,166	4,021	4,105	4,056	4,124	3,973	3,963	3,960	186	194	191	189	179

CO2 Reduction From 2005 (%)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	31.0%	20.0%	12.0%	15.0%	19.0%	16.0%	17.0%	16.0%	19.0%	19.0%	21.0%	20.0%	22.0%	21.0%	96.0%	96.0%
Optimized - East Bend Natural Gas Conversion by 2030	24.9%	14.9%	11.4%	13.8%	16.5%	54.9%	59.2%	67.1%	74.5%	77.9%	79.5%	80.5%	80.9%	82.6%	82.9%	84.2%
Optimized - East Bend Retirement by 2036	32.0%	19.0%	11.0%	15.0%	18.0%	16.0%	17.0%	16.0%	19.0%	19.0%	19.0%	96.0%	96.0%	96.0%	96.0%	96.0%

Figure 6.8: CO2 Reduction – Alternate without EPA CAA Section 111 Update

2005 Base (000 tons)
4,912

Annual CO2 Emissions (000 tons)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	3,214	3,865	4,328	4,189	3,980	4,101	4,087	4,117	4,019	4,001	3,929	3,969	3,854	3,915	1,905	1,858
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	3,222	3,896	4,348	4,167	4,021	4,102	4,072	4,075	3,994	3,971	3,936	3,920	3,816	3,853	452	376
Alternate - East Bend DFO Conversion with CC Replacement by 2036	3,212	3,894	4,343	4,145	4,001	4,089	4,072	4,105	4,025	3,986	3,911	1,963	1,916	1,908	1,905	1,857
Alternate - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewable	3,284	3,926	4,356	4,130	4,011	4,077	4,083	4,096	3,947	3,872	3,912	3,881	3,808	3,834	1,874	1,816
Preferred - East Bend Retirement by 2036 and Accelerated Renewables	3,324	4,002	4,293	4,201	4,033	4,105	3,985	4,049	3,989	3,918	3,879	1,941	1,887	1,878	1,872	1,816
Alternate - East Bend Retirement by 2042	3,413	3,980	4,362	4,178	4,035	4,107	4,055	4,116	4,017	3,949	3,910	3,905	3,833	3,929	3,679	3,756

CO2 Reduction From 2005 (%)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	34.6%	21.3%	11.9%	14.7%	19.0%	16.5%	16.8%	16.2%	18.2%	18.5%	20.0%	19.2%	21.5%	20.3%	61.2%	62.2%
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	34.4%	20.7%	11.5%	15.2%	18.1%	16.5%	17.1%	17.0%	18.7%	19.2%	19.9%	20.2%	22.3%	21.6%	90.8%	92.3%
Alternate - East Bend DFO Conversion with CC Replacement by 2036	34.6%	20.7%	11.6%	15.6%	18.5%	16.8%	17.1%	16.4%	18.1%	18.8%	20.4%	60.0%	61.0%	61.2%	61.2%	62.2%
Alternate - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewable	33.1%	20.1%	11.3%	15.9%	18.3%	17.0%	16.9%	16.6%	19.6%	21.2%	20.4%	21.0%	22.5%	21.9%	61.9%	63.0%
Preferred - East Bend Retirement by 2036 and Accelerated Renewables	32.3%	18.5%	12.6%	14.5%	17.9%	16.4%	18.9%	17.6%	18.8%	20.2%	21.0%	60.5%	61.6%	61.8%	61.9%	63.0%
Alternate - East Bend Retirement by 2042	30.5%	19.0%	11.2%	14.9%	17.9%	16.4%	17.4%	16.2%	18.2%	19.6%	20.4%	20.5%	22.0%	20.0%	25.1%	23.5%

STAFF-DR-01-020

REQUEST:

Refer to the IRP, Figures 6.9-6.12, pages 53–55.

a. Provide the data supporting each of the figures (including the data used to calculate the percentages) in excel format with all cells visible and unprotected.

b. Refer also to the IRP, page 16. Explain whether the PJM prices used to obtain prices within the DEOK PJM Load Zone reflect the assumptions used to run each of the scenarios determining energy market purchases.

c. If the answer to part b. is in the affirmative, explain how Duke Kentucky modeled the various EPA Section 111 compliance strategies in entire Eastern Interconnect to determine energy prices in the DEOK PJM Load Zone in order to ensure the consistent application of modeling assumptions.

RESPONSE:

a. Please see STAFF-DR-01-020 Attachment for data supporting all figures.

b. Yes, the same modeling assumptions for 111 were used within the National Database.

c. The Company looked at all coal units in the eastern interconnect with retirements past 2032 and 50% of the remaining MW's with planned retirements after 2032 were instead converted into DFO units, while the other half moved up the retirement dates to 2032. The units with the earliest retirement dates after 2032 made up all the forced early retirements. For new gas resources capacity factors limits were assumed on new resources in all areas starting 2032, apart from areas where geology appears to be favorable for Carbon Capture Sequestration (CCS) in which the only combined cycle option to build was a CC with CCS which had no capacity factor limit.

PERSON RESPONSIBLE: Tyler Cook

Figure 6.9: Market Purchases – Optimized with EPA CAA Section 111 Update

Total Load (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
	4,284	4,291	4,285	4,291	4,282	4,363	4,370	4,390	4,400	4,420	4,525	4,561	4,577	4,603	4,630	4,677

Market Purchases (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	2,257	1,748	1,299	1,467	1,500	1,720	1,904	1,579	2,018	2,412	3,209	3,377	3,309	3,210	509	561
Optimized - East Bend Natural Gas Conversion by 2030	2,282	1,614	1,372	1,446	1,525	1,809	2,092	1,968	3,520	3,910	4,336	4,445	4,382	4,348	4,443	4,063
Optimized - East Bend Retirement by 2032	2,109	1,582	1,314	1,456	1,436	1,497	1,522	2,523	2,483	2,524	3,058	3,063	2,871	2,819	2,900	3,091

Market Purchases (%) of Total Load	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Optimized - East Bend DFO Conversion by 2030	53.0%	41.0%	30.0%	34.0%	35.0%	39.0%	44.0%	36.0%	46.0%	55.0%	71.0%	74.0%	72.0%	70.0%	11.0%	12.0%
Optimized - East Bend Natural Gas Conversion by 2030	53.3%	37.6%	32.0%	33.7%	35.6%	41.5%	47.9%	44.8%	80.0%	88.5%	95.8%	97.5%	95.7%	94.5%	96.0%	86.9%
Optimized - East Bend Retirement by 2032	49.2%	36.9%	30.7%	33.9%	33.5%	34.3%	34.8%	57.5%	56.4%	57.1%	67.6%	67.2%	62.7%	61.3%	62.6%	66.1%

Figure 6.10: Market Purchases – Alternate with EPA CAA Section 111 Update

Total Load (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	4,284	4,291	4,285	4,291	4,282	4,363	4,370	4,390	4,400	4,420	4,525	4,561	4,577	4,603	4,630	4,677

Market Purchases (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alternate - East Bend DFO Conversion with CC Replacement by 2039	2,413	1,764	1,389	1,457	1,539	1,746	1,869	1,544	1,898	2,381	3,367	3,072	3,168	3,485	2,139	2,107
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	2,340	1,759	1,399	1,475	1,485	1,804	1,804	1,502	1,849	2,397	3,207	3,136	3,401	3,453	2,081	1,924
Alternate - East Bend DFO Conversion with CC w/CCS Replacement by 2036	2,289	1,716	1,318	1,486	1,513	1,744	1,852	1,524	2,018	2,516	3,217	412	448	460	466	447
Preferred - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	2,292	1,676	1,328	1,476	1,457	1,674	1,790	1,485	1,703	2,148	2,770	2,997	2,869	2,838	2,076	2,086
Alternate - East Bend Retirement by 2032 with CC Replacement	2,085	1,580	1,337	1,516	1,471	1,493	1,573	2,277	2,387	2,436	2,310	2,186	2,171	2,201	2,267	2,114

Market Purchases (%) of Total Load	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alternate - East Bend DFO Conversion with CC Replacement by 2039	56.3%	41.1%	32.4%	34.0%	35.9%	40.0%	42.8%	35.2%	43.1%	53.9%	74.4%	67.4%	69.2%	75.7%	46.2%	45.0%
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	54.6%	41.0%	32.7%	34.4%	34.7%	41.4%	41.3%	34.2%	42.0%	54.2%	70.9%	68.8%	74.3%	75.0%	45.0%	41.1%
Alternate - East Bend DFO Conversion with CC w/CCS Replacement by 2036	53.4%	40.0%	30.8%	34.6%	35.3%	40.0%	42.4%	34.7%	45.9%	56.9%	71.1%	9.0%	9.8%	10.0%	10.1%	9.6%
Preferred - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	53.5%	39.1%	31.0%	34.4%	34.0%	38.4%	41.0%	33.8%	38.7%	48.6%	61.2%	65.7%	62.7%	61.7%	44.8%	44.6%
Alternate - East Bend Retirement by 2032 with CC Replacement	48.7%	36.8%	31.2%	35.3%	34.3%	34.2%	36.0%	51.9%	54.3%	55.1%	51.1%	47.9%	47.4%	47.8%	49.0%	45.2%

Figure 6.11: Market Purchases – Optimized without EPA CAA Section 111 Update

Total Load (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	4,284	4,291	4,285	4,291	4,282	4,363	4,370	4,390	4,400	4,420	4,525	4,561	4,577	4,603	4,630	4,677

Market Purchases (GWh)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Optimized - East Bend DFO Conversion by 2030	2,228	1,716	1,371	1,502	1,542	1,527	1,573	1,580	1,584	1,635	1,719	1,733	1,831	1,795	463	468
Optimized - East Bend Natural Gas Conversion by 2030	1,953	1,469	1,312	1,448	1,466	2,177	2,619	3,293	3,890	4,175	4,363	4,341	4,368	4,360	4,231	4,073
Optimized - East Bend Retirement by 2032	2,185	1,545	1,371	1,416	1,499	1,483	1,530	1,536	1,628	1,591	1,629	456	458	506	509	561

Market Purchases (%) of Total Load	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Optimized - East Bend DFO Conversion by 2030	52.0%	40.0%	32.0%	35.0%	36.0%	35.0%	36.0%	36.0%	36.0%	37.0%	38.0%	38.0%	40.0%	39.0%	10.0%	10.0%
Optimized - East Bend Natural Gas Conversion by 2030	45.6%	34.2%	30.6%	33.7%	34.2%	49.9%	59.9%	75.0%	88.4%	94.4%	96.4%	95.2%	95.4%	94.7%	91.4%	87.1%
Optimized - East Bend Retirement by 2036	51.0%	36.0%	32.0%	33.0%	35.0%	34.0%	35.0%	35.0%	37.0%	36.0%	36.0%	10.0%	10.0%	11.0%	11.0%	12.0%

Figure 6.12: Market Purchases – Alternate without EPA CAA Section 111 Update

Total Load (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
	4,284	4,291	4,285	4,291	4,282	4,363	4,370	4,390	4,400	4,420	4,525	4,561	4,577	4,603	4,630	4,677

Market Purchases (GWh)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	2,380	1,737	1,341	1,439	1,562	1,583	1,542	1,542	1,598	1,609	1,707	1,701	1,805	1,759	426	594
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	2,401	1,776	1,296	1,452	1,522	1,530	1,570	1,555	1,614	1,617	1,695	1,750	1,846	1,826	2,001	1,893
Alternate - East Bend DFO Conversion with CC Replacement by 2036	2,371	1,764	1,314	1,473	1,553	1,529	1,569	1,551	1,612	1,564	1,727	256	338	366	427	601
Alternate - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewable	2,333	1,691	1,310	1,507	1,473	1,498	1,470	1,445	1,467	1,541	1,490	1,513	1,486	1,510	288	413
Preferred - East Bend Retirement by 2036 and Accelerated Renewables	2,197	1,570	1,349	1,422	1,388	1,379	1,497	1,438	1,407	1,464	1,422	196	243	262	276	410
Alternate - East Bend Retirement by 2042	2,108	1,551	1,336	1,499	1,494	1,479	1,516	1,504	1,511	1,613	1,634	1,729	1,758	1,673	1,908	1,880

Market Purchases (%) of Total Load	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Alternate - East Bend DFO Conversion with CC Replacement by 2039	55.6%	40.5%	31.3%	33.5%	36.5%	36.3%	35.3%	35.1%	36.3%	36.4%	37.7%	37.3%	39.4%	38.2%	9.2%	12.7%
Alternate - East Bend DFO Conversion with SMR Replacement by 2039	56.1%	41.4%	30.2%	33.9%	35.6%	35.1%	35.9%	35.4%	36.7%	36.6%	37.5%	38.4%	40.3%	39.7%	43.2%	40.5%
Alternate - East Bend DFO Conversion with CC Replacement by 2036	55.4%	41.1%	30.7%	34.3%	36.3%	35.0%	35.9%	35.3%	36.6%	35.4%	38.2%	5.6%	7.4%	8.0%	9.2%	12.8%
Alternate - East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewable	54.5%	39.4%	30.6%	35.1%	34.4%	34.3%	33.6%	32.9%	33.3%	34.9%	32.9%	33.2%	32.5%	32.8%	6.2%	8.8%
Preferred - East Bend Retirement by 2036 and Accelerated Renewables	51.3%	36.6%	31.5%	33.1%	32.4%	31.6%	34.3%	32.8%	32.0%	33.1%	31.4%	4.3%	5.3%	5.7%	6.0%	8.8%
Alternate - East Bend Retirement by 2042	49.2%	36.1%	31.2%	34.9%	34.9%	33.9%	34.7%	34.3%	34.3%	36.5%	36.1%	37.9%	38.4%	36.4%	41.2%	40.2%

STAFF-DR-01-021

REQUEST:

Refer to IRP, page 57 regarding sensitivity analysis. Explain why decrease to load forecast was not included as a sensitivity.

RESPONSE: While a "Low" load forecast was developed and presented in Appendix B to the 2024 IRP based on the Staff Comments from the 2021 IRP, the low load forecast was not modeled as a sensitivity because the resulting portfolio would not have yielded material differences in build. The portfolio was fixed (i.e., EB converted to DFO in 2030 and replaced with a CC in 2039 w/ accelerated renewables) to meet the requirements of the CAA 111 Rule Update, and therefore there were no resources that could have been removed from the portfolio.

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-022

REQUEST:

Refer to the IRP, Figure 7.1, page 61.

a. Explain the timeline for East Bend to be converted to DFO.

b. Refer also to Figure 6.10, page 54. Explain whether Duke Kentucky market energy purchases in Figure 6.10 takes into account the DFO conversion of East Bend by December 31, 2029, as shown in Figure 7.1.

RESPONSE:

a. It is expected to take 4-5 years to convert East Bend to DFO. The onsite work scope includes a detailed boiler study, design engineering, air permit modification application, procurement of equipment, construction, and commissioning. The offsite work scope includes construction of a new natural gas lateral connecting the plant to an interstate mainline and the completion of any required mainline expansion projects. Additionally, the timeline includes applications and approvals for all of the necessary regulatory filings.

b. Duke Energy Kentucky market energy purchases in Figure 6.10 does take into account the DFO conversion of East Bend starting January 1, 2030. This is the date in the EnCompass model that the DFO conversion begins at East Bend. In modeling space, new resources and conversions always start on January 1st of a given year.

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-023

REQUEST:

Refer to the IRP, Figure 7.1, page 61.

a. Confirm that the portfolio represented by Figure 7.1 is the preferred plan.

b. Explain how the cost of this portfolio compares to the portfolios discussed and highlighted in Section 6.

c. Explain how Duke Kentucky chose this portfolio as its preferred portfolio as opposed to the portfolios evaluated in Section 6.

d. Refer also to Appendix H, Table H.3, page 153. Explain whether the table is based upon the portfolio in Figure 7.1 and how the two relate to each other. Include in the response, for Table H.3 break out the generation resources so make the comparison between Figure 7.1 and Table H.3 more apparent.

RESPONSE:

a. Correct, Figure 7.1 is the 2024 IRP preferred plan. This plan is compliant with rules under EPA CAA Section 111 Update while offering flexibility to adjust course as needed should those rules change.

b. Looking at the portfolio's under EPA CAA Section 111 Update, all portfolios have similar costs through most of the 2020's, no new resources were added in the short-term and East Bend was operating on coal. The cost differences begin in 2029 as many of the portfolios either convert East Bend to DFO or 100% natural gas in 2030. The conversion will increase the cost of those portfolios compared to a retire

East Bend in 2032 portfolio for a short period of time in the early 2030's. The portfolio in Table 7.1 provides the flexibility to operate East Bend on coal and gas, while accelerating renewables for incremental energy needs while relying less on the market for economic energy purchases as the other portfolios. This results in a portfolio whose cost is in the middle of the evaluated portfolios while maintaining operational flexibility in the current policy environment.

c. As explained in Chapter 6 and Chapter 7, the primary factors for selecting this portfolio include the portfolio's cost competitiveness, flexibility for futures with and without the EPA CAA Section 111 Update, and the risk mitigation it provides through increased fuel and fleet diversity and the moderate level of market purchases. Specifically, there are four compliance pathways for East Bend under the updated EPA CAA111 rule. These include 1) convert East Bend to dual fuel operation (DFO) by 2030, 2) convert East Bend to 100% natural gas by 2030, 3) retire East Bend by 2032, or 4) add carbon capture and sequestration (CCS) to East Bend by 2032. Only options 1, 2, and 3 are executable, and option 2 (natural gas conversion) leads to significant reliance on market purchases (>90% by 2034) as shown in Figure 6.9. Of the executable options that comply with the updated EPA CAA111 rule, DFO at East Bend being replaced with a NGCC in 2039 is the least cost option with the lowest level of exposure to fluctuating market conditions. Additionally, accelerating solar resources into the late 2020s leads to no impact on PVRR while increasing energy diversity of the Duke Energy Kentucky system.

PERSON RESPONSIBLE: Matthew Kalemba

STAFF-DR-01-024

REQUEST:

Refer to Duke Kentucky's 2024 Integrated Resource Plan (IRP), page 63, regarding the effects of Kentucky Senate Bills 4 and 349 and page 61, Figure 7.1.

a. State how much lead time Duke Kentucky needs from filing of notice with the Commission under Senate Bill 349 to completion of projects included in the preferred portfolios and provide an estimated timeline.

b. State whether this lead time was factored into the timing of modeling of new generation construction or conversion generation resources.

c. State what PJM interconnection queue lead time was factored into the timing of modeling of new generation construction or conversion generation resources and explain how that lead time was determined.

d. State whether the 50 MW of solar to be added in 2029 is intended to reflect power purchase agreements, purchase of existing or planned facilities, or self-built facilities.

RESPONSE:

a. The EPIC commission under KY SB349 requires 180 days and the PSC has 8 months to approve a CPCN following its acceptance (KRS 278.019). After receiving the CPCN order, it is currently taking 5+ years for long lead time equipment deliver and construction and commissioning of a CC. Prior to filing the

CPCN there is approximately 2-3 years of development activities required. Total timeline then from the time project development starts to unit in service is 8+ years.

b. This timeline was factored into the construction of new resources that may replace East Bend at some point in the future.

c. The Company assumed that conversion of East Bend to DFO would not require the Company entering into the PJM interconnection queue as this project is not adding incremental capacity to the site. When East Bend retires in 2038, the Company would need to enter the PJM interconnection queue for any incremental generation at that time (in this case, 64 MW). It is the Company's assumption that there is adequate time to enter the PJM queue and complete any necessary transmission network upgrades prior to executing the retirement and replacement of East Bend in 2038. For incremental solar resources online in 2029, the Company assumed that there would be resources available with completed interconnection agreements for an in-service date of 2029.

d. Duke Energy Kentucky modeled a generic solar resource for purposes of the IRP. The Company is evaluating next steps for sourcing this resource need.

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-025

REQUEST:

Refer to the IRP, page 74.

a. Provide PJM Base Residual Auction (BRA) clearing prices from the 2021/2022 through the 2024/2025 planning years in the DEOK PJM load Zone and in adjacent Load Zones.

b. Explain possible reasons for the differences in capacity prices.

c. Provide monthly average Locational Marginal Prices (LMPs) for the DEOK PJM Load Zone and in adjacent Load Zones and explain the extent to which and why Duke Kentucky might be subject to zonal pricing risk.

d. Explain if high BRA market clearing prices encourage the construction of transmission lines as well as generation resources.

e. Explain whether within a PJM Load Zone, the market clearing energy price is the same throughout the load zone and any differences in LMPs are the result of congestion and line loss.

RESPONSE:

a. PJM BRA Capacity Clearing Prices are shown below for the RTO Zone and DEOK Zone for 2021/2022 through 2024/2025.

BRA Year	RTO Zone Price	DEOK Zone Price
2021/2022	$140/MW-Day	$140/MW-Day
2022/2023	$50/MW-Day	$71.69/MW-Day

2023/2024	$34.13/MW-Day	$34.13/MW-Day
2024/2025	$28.92/MW-Day	$96.24/MW-Day
2025/2026	$269.92/MW-Day	$269.92/MW-Day

Adjacent zone prices cleared at the same price as the RTO zone price. For detail showing a history of all capacity pricing zones, please see STAFF-DR-01-025 Attachment 1, which was downloaded from the PJM website.

b. There are multiple reasons why the PJM clearing prices can be different between capacity zones. Specifically related to DEOK, the reasons include the DEOK Capacity Emergency Transfer Objective (CETO), DEOK Capacity Emergency Transfer Limit (CETL), DEOK Reliability Requirement, the amount of generation within the DEOK zone, the offer prices of generating resources within DEOK in the BRA or Incremental Auction (IA), and the Cost of New Entry (CONE) price. Please refer to the response to KSES-DR-01-024 for an example of these parameters from the PJM planning parameters report.

c. Note that this response is referring to the PJM energy market and not the capacity market as previously discussed. Day-Ahead and Real-Time Locational Marginal Price (LMP) monthly averages for the Duke Energy Kentucky load zone as well as the DEOK, AEP, and DPL load zones are attached as STAFF-DR-01-025 Attachment 2. The Company is subject to the different energy prices through the Day-Ahead and Real-Time LMP for Day-Ahead generation awards, Day-Ahead demand bids, Real-time (actual) generation amounts, and Real-time (actual) customer demand.

d. Referring to the capacity market price from the BRA, this is possible, yes.

e. Note that this response is confined to the PJM energy market and not the capacity market as previously discussed. Locational Marginal Price (LMP) has three components: a marginal energy component, a marginal loss component, and a marginal congestion component. The Company agrees that the marginal energy component is the same for each LMP node within a load zone (and the energy component of LMP is in fact the same for every LMP node across all of PJM), with the only difference between LMP values being the result of marginal congestion and loss components of LMP.

PERSON RESPONSIBLE: John Swez

Resource Clearing Prices for all RPM Auctions held to date

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND	COMED	BGE	PL	DAYTON	DEOK	DOM	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2
DY 07/08																							
BRA	*	$40.80	**	**	$197.67	$188.54	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 08/09																							
BRA	*	$111.92	**	**	$148.80	$210.11	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$10.00	**	**	$10.00	$223.85	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 09/10																							
BRA	*	$102.04	**	$191.32	**	$237.33	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$40.00	**	$86.00	**	**	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 10/11																							
BRA	*	$174.29	**	**	**	**	**	**	$186.12	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$50.00	**	**	**	**	**	**	$50.00	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 11/12																							
BRA	*	$110.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$55.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$5.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 12/13																							
BRA	*	$16.46	$133.37	**	$139.73	$133.37	**	$185.00	$222.30	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$16.46	$16.46	**	$153.67	$16.46	**	$153.67	$153.67	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	*	$13.01	$13.01	**	$48.91	$13.01	**	$48.91	$48.91	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$2.51	$2.51	**	$2.51	$2.51	**	$2.51	$2.51	**	N/A	N/A	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 13/14																							
BRA	*	$27.73	$226.15	**	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$20.00	$20.00	**	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	*	$7.01	$10.00	**	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$4.05	$30.00	**	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 14/15																							
BRA	Annual	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$125.47	$125.47	**	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$0.03	$5.23	**	$5.23	$5.23	$5.23	$399.62	$5.23	$5.23	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Limited	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 15/16																							
BRA	Annual	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$118.54	$150.00	**	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$123.56	$141.12	**	$141.12	$141.12	$155.02	$155.02	$141.12	$141.12	$204.10	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$163.20	$184.77	**	$184.77	$184.77	$185.00	$185.00	$184.77	$184.77	$163.20	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$163.20	$184.77	**	$184.77	$184.77	$185.00	$185.00	$184.77	$184.77	$163.20	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A

Resource Clearing Prices for all RPM Auctions held to date

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND	COMED	BGE	PL	DAYTON	DEOK	DOM	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2
3IA	Limited	$100.76	$122.33	**	$122.33	$122.33	$122.56	$122.56	$122.33	$122.33	$100.76	**	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 16/17																							
BRA	Annual	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$94.45	$94.45	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$60.00	$119.13	**	$119.13	$119.13	$244.22	$244.22	$119.13	$119.13	$100.52	$100.52	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$60.00	$119.13	**	$119.13	$119.13	$244.22	$244.22	$119.13	$119.13	$100.52	$100.52	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$53.93	$89.35	**	$89.35	$89.35	$214.44	$214.44	$89.35	$89.35	$94.45	$94.45	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
TA	CP	$134.00	$134.00	**	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Limited	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 17/18																							
BRA	Annual	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	**	**	**	$120.00	N/A	$120.00	$120.00	N/A
BRA	Ext Summer	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$53.98	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$106.02	$106.02	**	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02	$106.02	$106.02	$40.00	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	**	**	**	N/A	N/A	N/A	N/A	N/A
TA	CP	$151.50	$151.50	**	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	Ext Summer	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	Limited	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	**	**	**	NA ***	NA ***	NA ***	$26.50	NA ***
3IA	Annual	$36.49	$36.49	**	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	Ext Summer	$36.49	$36.49	**	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	Limited	$36.49	$36.49	**	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49				NA ***	NA ***	NA ***	NA ***	NA ***
DY 18/19																							
BRA	CP	$164.77	$164.77	**	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$164.77	$215.00	$164.77	$164.77	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE GEN	$149.98	$149.98	**	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$149.98	$200.21	$149.98	$75.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE DR/EE	$149.98	$149.98	**	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$149.98	$200.21	$59.95	$75.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	CP	$27.15	$27.15	**	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$27.15	$30.00	$27.15	$27.15	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE GEN	$22.51	$22.51	**	$80.04	$22.51	$80.04	$80.04	$35.68	$22.51	$22.51	$22.51	$25.36	$22.51	$22.51	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE DR/EE	$22.51	$22.51	**	$80.04	$22.51	$80.04	$80.04	$35.68	$22.51	$22.51	$22.51	$25.36	$22.51	$22.51	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	CP	$50.00	$50.00	**	$80.02	$50.00	$80.02	$80.02	$80.02	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	BASE GEN	$5.00	$5.00	**	$35.02	$5.00	$35.02	$35.02	$30.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	BASE DR/EE	$5.00	$5.00	**	$35.02	$5.00	$35.02	$35.02	$30.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	CP	$34.99	$34.99	**	$40.00	$34.99	$40.00	$40.00	$40.00	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	BASE GEN	$14.29	$14.29	**	$19.30	$14.29	$19.30	$19.30	$5.00	$14.29	$14.29	$14.29	$14.29	$3.50	$14.29	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	BASE DR/EE	$14.29	$14.29	**	$19.30	$14.29	$19.30	$19.30	$5.00	$14.29	$14.29	$14.29	$14.29	$3.50	$14.29	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 19/20																							
BRA	CP	$100.00	$100.00	**	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$100.00	$202.77	$100.30	$100.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE GEN	$80.00	$80.00	**	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$80.00	$182.77	$80.30	$80.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE DR/EE	$80.00	$80.00	**	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$80.00	$182.77	$80.30	$80.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	CP	$51.33	$51.33	**	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33	$51.33	$51.33	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE GEN	$15.00	$15.00	**	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE DR/EE	$15.00	$15.00	**	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	CP	$32.87	$32.87	**	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00	$32.87	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	BASE GEN	$10.01	$10.01	**	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	BASE DR/EE	$10.01	$10.01	**	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***

Resource Clearing Prices for all RPM Auctions held to date

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND	COMED	BGE	PL	DAYTON	DEOK	DOM	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2
3IA	CP	$28.35	$28.35	**	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	BASE GEN	$21.35	$21.35	**	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	BASE DR/EE	$21.35	$21.35	**	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35	$21.35	$21.35	**	**	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 20/21																							
BRA	CP	$76.53	$86.04	**	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$76.53	$188.12	$86.04	$86.04	$76.53	$130.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	CP	$42.90	$42.90	**	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	CP	$20.25	$20.25	**	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	CP	$10.00	$15.25	**	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$10.00	$15.25	$15.25	$10.00	$10.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 21/22																							
BRA	CP	$140.00	$140.00	**	$165.73	$140.00	$204.29	$204.29	$165.73	$140.00	$171.33	$171.33	$195.55	$200.30	$140.00	$140.00	$140.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	CP	$23.00	$23.00	**	$25.00	$23.00	$45.00	$219.00	$25.00	$23.00	$23.00	$23.00	$23.00	$60.00	$23.00	$23.00	$23.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	CP	$10.26	$10.26	**	$15.37	$10.26	$125.00	$125.00	$15.37	$10.26	$10.26	$10.26	$10.26	$70.00	$10.26	$10.26	$10.26	**	NA ***	NA ***	NA ***	NA ***	NA ***
3IA	CP	$20.55	$20.55	**	$26.36	$20.55	$31.00	$31.00	$26.36	$20.55	$20.55	$20.55	$20.55	$39.00	$20.55	$20.55	$20.55	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 22/23																							
BRA	CP	$50.00	$95.79	**	$97.86	$95.79	$97.86	$97.86	$97.86	$95.79	$50.00	$50.00	$68.96	$126.50	$95.79	$50.00	$71.69	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA												*** AUCTION CANCELLED ***											
2IA												*** AUCTION CANCELLED ***											
3IA	CP	$19.00	$35.00	**	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00	$19.00	$19.00	$19.00	$35.00	$35.00	$19.00	$19.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 23/24																							
BRA	CP	$34.13	$49.49	**	$49.49	$49.49	$49.49	$49.49	$69.95	$49.49	$34.13	$34.13	$34.13	$69.95	$49.49	$34.13	$34.13	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA												*** AUCTION CANCELLED ***											
2IA												*** AUCTION CANCELLED ***											
3IA	CP	$37.53	$49.49	**	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$37.53	$79.03	$49.49	$37.53	$37.53	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 24/25																							
BRA	CP	$28.92	$49.49	**	$53.60	$49.49	$53.60	$53.60	$426.17	$49.49	$28.92	$28.92	$28.92	$73.00	$49.49	$28.92	$96.24	**	NA ***	NA ***	NA ***	NA ***	NA ***
1IA												*** AUCTION CANCELLED ***											
2IA												*** AUCTION CANCELLED ***											
3IA	CP	$58.00	$80.00	**	$175.81	$80.00	$175.81	$175.81	$175.81	$80.00	$58.00	$58.00	$58.00	$155.29	$80.00	$58.00	$58.00	**	NA ***	NA ***	NA ***	NA ***	NA ***
DY 25/26																							
BRA	CP	$269.92	$269.92	**	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$466.35	$269.92	$269.92	$269.92	$444.26	NA ***	NA ***	NA ***	NA ***	NA ***
1IA												*** AUCTION CANCELLED ***											
2IA												*** AUCTION CANCELLED ***											
3IA	CP																						

* The Annual, Extended Summer and Limited capacity product types were implemented starting with the 2014/2015 Delivery Year
** LDA was not modeled
*** There were no Sell Offers in these External Source Zones.

Time Series Function	PnodeID=128774185 TotalLMP|Monthly|Default|Default|America/New_York PJM_Da_Hourly_Lmp	PnodeID=1069452904 TotalLMP|Monthly|Default|Default|America/New_York PJM_Da_Hourly_Lmp	PnodeID=1269364670 TotalLMP|Monthly|Default|Default|America/New_York PJM_Da_Hourly_Lmp	PnodeID=116472941 TotalLMP|Monthly|Default|Default|America/New_York PJM_Da_Hourly_Lmp
Date (America/New_York)	PJM Day Ahead Hourly LMP, DEK AGGREGATE , PnodeID: 128774185	PJM Day Ahead Hourly LMP, DEOK_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 1069452904	PJM Day Ahead Hourly LMP, AEPOHIO_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 1269364670	PJM Day Ahead Hourly LMP, DPL_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 116472941
1/1/2019	30.89	32.11	31.57	35.95
2/1/2019	26.62	26.87	27.04	25.67
3/1/2019	29.04	29.32	29.66	27.9
4/1/2019	26.46	26.77	26.66	24.35
5/1/2019	24.93	25.21	25.17	20.65
6/1/2019	22.96	23.18	22.67	21.94
7/1/2019	28.92	29.5	28.25	32.89
8/1/2019	25.06	25.15	24.63	23.4
9/1/2019	27.68	27.72	27.58	19.45
10/1/2019	26.68	26.85	26.95	18.02
11/1/2019	30.39	30.37	29.66	24.38
12/1/2019	23.86	24.1	23.65	22.68
1/1/2020	22.24	22.32	22.27	21.67
2/1/2020	20.26	20.31	20.15	18.06
3/1/2020	18.45	18.53	18.63	16.04
4/1/2020	17.16	17.29	18.03	15.94
5/1/2020	18.11	18.21	18.43	14.24
6/1/2020	19.49	19.69	19.04	17.04
7/1/2020	25.53	25.54	25.06	26.89
8/1/2020	22.92	22.94	22.94	20.86
9/1/2020	20.08	20.24	19.74	15.78
10/1/2020	23.76	24.13	22.32	15.89
11/1/2020	21.32	21.59	21.2	19.49
12/1/2020	25.06	25.4	24.93	29.49
1/1/2021	25.66	25.89	24.98	23.84
2/1/2021	43.54	43.85	42.94	41.92
3/1/2021	25.04	25.88	24.79	35.51
4/1/2021	29.03	29.44	28.68	21.95
5/1/2021	31.38	32.1	28.73	23.57
6/1/2021	32.32	32.32	31.71	29.82
7/1/2021	37.23	37.27	36.62	36.81
8/1/2021	42.78	42.67	42.27	43.01
9/1/2021	45.03	45.01	44.81	38.74
10/1/2021	58.85	59.08	59.19	45.97
11/1/2021	65.82	65.46	64.23	49.89
12/1/2021	39.03	38.8	37.27	42.92
1/1/2022	55.03	54.98	53.5	72.7
2/1/2022	47.42	47.31	47.49	54.46
3/1/2022	46.3	46.29	45.54	42.22
4/1/2022	66.94	66.7	66.19	54.81
5/1/2022	79.79	79.42	78.44	61.47
6/1/2022	92.35	90.38	89.28	61.64
7/1/2022	91.14	90.19	89.32	91.16
8/1/2022	96.65	95.97	94.65	104.51
9/1/2022	80.69	81.18	79.54	61.59
10/1/2022	60.76	61.17	60.78	51.15
11/1/2022	54.29	54.84	53.92	45.63
12/1/2022	83.77	84.3	83.47	93.29
1/1/2023	36.9	37.11	37.39	30.66
2/1/2023	28.43	28.61	28.6	31.47
3/1/2023	29.99	30.06	29.1	24.1
4/1/2023	30.95	31.09	30.57	23.88
5/1/2023	31.76	32.63	30.85	15.82
6/1/2023	28.54	28.95	27.42	17.97
7/1/2023	36.86	37.11	36.37	44.95
8/1/2023	30.83	31.02	30.03	25.96
9/1/2023	29.87	30.19	29.54	25.19
10/1/2023	35.06	35.48	35.74	18.44
11/1/2023	31.63	31.76	31.54	27.84
12/1/2023	26.98	27.14	26.98	28.9

Time Series Function	PnodeID=128774185 TotalLMP|Monthly|Default|Default|America/New_York PJM_Rt_Hourly_Lmp	PnodeID=1069452904 TotalLMP|Monthly|Default|Default|America/New_York PJM_Rt_Hourly_Lmp	PnodeID=1269364670 TotalLMP|Monthly|Default|Default|America/New_York PJM_Rt_Hourly_Lmp	PnodeID=116472941 TotalLMP|Monthly|Default|Default|America/New_York PJM_Rt_Hourly_Lmp
Date (America/New_York)	PJM Real Time Hourly LMP, DEK AGGREGATE , PnodeID: 128774185	PJM Real Time Hourly LMP, DEOK_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 1069452904	PJM Real Time Hourly LMP, AEPOHIO_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 1269364670	PJM Real Time Hourly LMP, DPL_RESID_AGG RESIDUAL_METERED_EDC , PnodeID: 116472941
1/1/2019	28.45	28.91	29.35	34.74
2/1/2019	27.47	27.71	27.93	26.53
3/1/2019	28.58	28.93	29.33	27.66
4/1/2019	26.27	26.53	26.39	25.12
5/1/2019	23.77	23.92	24.24	20.84
6/1/2019	23.04	23.29	22.89	21.44
7/1/2019	28.33	28.9	28.54	35.44
8/1/2019	23.89	24.14	23.92	21.63
9/1/2019	29.74	30.03	31.82	21.42
10/1/2019	29.11	29.43	29.95	17.97
11/1/2019	29.55	29.65	28.92	23.06
12/1/2019	23.16	23.4	23.1	22.8
1/1/2020	21.95	22.07	22.1	21.39
2/1/2020	19.46	19.54	19.53	18.52
3/1/2020	18.32	18.41	18.43	16.52
4/1/2020	17.48	17.61	18.81	16.48
5/1/2020	18.6	18.73	19	14.2
6/1/2020	19.62	19.69	19.56	16.56
7/1/2020	24.77	25.06	26.12	28.03
8/1/2020	23.33	23.45	23.68	21.05
9/1/2020	19.42	19.54	19.23	20.93
10/1/2020	24.11	24.7	23.51	17.26
11/1/2020	21.53	21.97	21.48	19.84
12/1/2020	24.76	25.15	24.97	32.76
1/1/2021	25.18	25.43	24.67	23.59
2/1/2021	41.35	41.51	39.58	39.11
3/1/2021	25.5	26.12	25.56	49.92
4/1/2021	26.95	27.34	27.63	20.27
5/1/2021	32.05	32.91	28.74	23.29
6/1/2021	31.54	31.89	31.95	28.81
7/1/2021	35.7	36.04	35.5	35.4
8/1/2021	43.28	43.5	43.7	46.06
9/1/2021	47.03	47.21	47.32	40.29
10/1/2021	59.3	59.44	59.37	48.22
11/1/2021	66.43	66.56	66.53	49.53
12/1/2021	39.41	39.34	38.12	42.2
1/1/2022	50.78	50.87	50.87	86.6
2/1/2022	45.08	45.14	44.73	56.43
3/1/2022	45.13	45.06	44.03	41.85
4/1/2022	65.85	65.84	65.59	51.25
5/1/2022	76.41	76.25	75.49	57.95
6/1/2022	95.11	94.86	94.75	66.44
7/1/2022	86.81	87.26	86.5	95.85
8/1/2022	96.75	97.27	95.66	112.63
9/1/2022	76.67	76.09	74.83	55.39
10/1/2022	57.62	57.93	57.47	51.82
11/1/2022	51.36	51.66	50.55	42.71
12/1/2022	120	120.73	117.82	123.65
1/1/2023	35.64	35.84	35.93	31.27
2/1/2023	25.01	25.14	25.41	29.39
3/1/2023	29.78	29.82	28.61	23.15
4/1/2023	29.59	29.68	28.99	22.76
5/1/2023	32.2	32.6	29.86	14.22
6/1/2023	27.67	27.83	26.89	18.5
7/1/2023	33.82	34.06	34	47.79
8/1/2023	31.25	31.45	30.34	28.59
9/1/2023	29.64	29.94	29.41	23.54
10/1/2023	33.72	33.93	34.31	16.46
11/1/2023	30.35	30.5	30.07	31.12
12/1/2023	27	27.13	27.13	28.22

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-026

REQUEST:

Refer to the IRP, page 73. Duke Kentucky states, "These projects include studies of customer satisfaction, appliance saturation studies, end-use, and competition (to monitor customer switching percentages in order to forecast future utility load); and related marketing research projects." Describe the nature of the competition Duke Kentucky faces and which customer classes are switching sources of energy.

RESPONSE:

The Company faces challenges in residential and nonresidential classes as it related to switching source of energy. Specifically, the customers can choose natural gas as an alternative to electricity. For example, many residential customers prefer natural gas for heating purposes during the colder months. Nonresidential customers also have a choice to natural gas for heating and water as well as using heat in their industrial processes. The Company uses Itron end-use intensities to incorporate these trends into its forecast.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-027

REQUEST:

Refer to the IRP, page 74. Provide a copy of Itron, Inc.'s statistically adjusted end-use (SAE) methodology and an explanation of how variables incorporating weather and energy efficiency are derived.

RESPONSE:

Weather is reflected in the heating and cooling variables. The heating and cooling variables are derived using Heating Degree Days (HDD 65) and Cooling Degree Days (CDD 65), respectively. The heating variable is derived by multiplying the following three variables: Use, weather, and heating intensity.

Use is derived by indexing economic and price variables.

Weather is indexed based on the heating variable.

Heating intensity includes the total heating intensities of all heating appliances, obtained from Itron, and calibrated against the Company's data.

The cooling variable is derived in a similar manner with CDDs.

Energy efficiency, as measured by the Company's sponsored Utility Energy Efficiency (UEE) programs, is reflected in the dependent variable. For historical data, the energy savings are added back to the sales figures, while the forecasted output is adjusted by reducing it for embedded UEE and forecasted UEE savings.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-028

REQUEST:

Refer to the IRP, page 74.

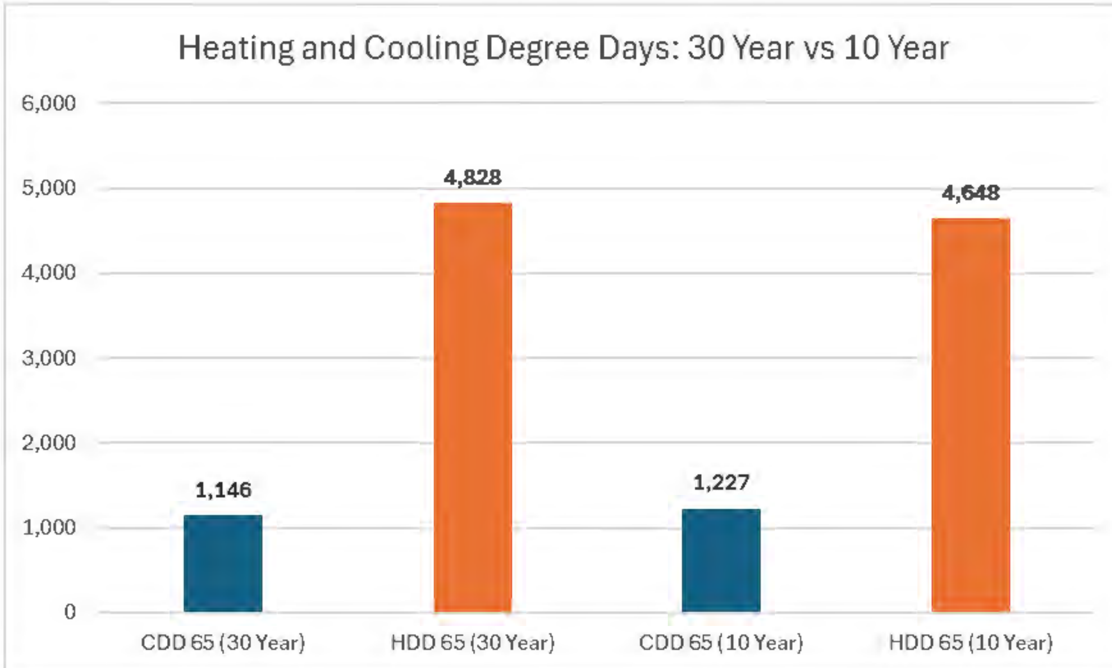
a. Explain whether the use of the 30-year window versus the use of a 10-year window could cause an understatement of forecast peak demand.

b. Provide a graph illustrating the volatility differences between 10-year and 30-year weather windows.

RESPONSE:

a. The Company uses a 30-year window to produce a more stable forecast, as it is less susceptible to year-to-year variations caused by updated weather data. As shown in the chart below – comparing the 30-year vs ten-year weather statistics over the course of the year provides only a minimal difference in the number of HDD's (4%) and CDD's (7%). As these differences are over the entire cooling and heating seasons, the peak would be impacted less than this. Isolating the month of July and August, the CDD difference between the 10 year and 30-year averages would be only +3% and -2% respectively.

b. The graph below compares the normal HDDs and CDDs over two period: a 30-year average vs. 10-year average.



PERSON RESPONSIBLE: Ibrar Khera

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-029

REQUEST:

Refer to the IRP, Tables B.10 and B.11, pages 85–86. Confirm that the energy forecasts are presented in megawatt hours (MWh)

RESPONSE:

The energy forecasts are presented in megawatt hours.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-030

REQUEST:

Refer to the IRP, Tables B.12-B.15, pages 88–90.

a. Explain the significant decrease in load forecast for 2024 (summer and winter) and for 2025 (winter).

b. Refer also to the IRP, Table H.3, page 153. Table H.3 does not match Tables B.12-B.15. Explain the basis for the peak load forecast presented in Table H.3 and explain any differences between Table H.3 and its corresponding table on pages 88–90.

RESPONSE:

a. The observed dip in the forecast can be attributed to the methodology employed in the regression model, which leveraged over 10 years of historical data. The model is built on a long-term downward trend in the peak load, the forecast output logically extends from that trend. The actual summer peak for 2024 was 823 in July, after normalization the actual peak would be within one percent for the forecasted peak of 808.

b. The correct data is provided in response to Staff-DR-01-032 which aligns with Table H.3.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-031

REQUEST:

Refer to the IRP, Table B.15, page 90 and Table B.17, page 92. Explain the slight differences between the tables.

RESPONSE:

The discrepancy between the two tables is attributable to a minor rounding discrepancy. Upon closer examination, the figures in Table B.15 appears to reflect the correct rounding.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-032

REQUEST:

Refer to the IRP, Table B.19.

a. Confirm that the data presented represents Duke Kentucky's summer energy and peak load forecasts.

b. Explain whether the data presented is before or after demand response (DR) and which other table(s) do the data correspond.

RESPONSE:

The data presented in Table B.19 represents summer peak after EE and before DR. The data should have aligned with the results presented in B.18. Upon closer inspection, there was an oversight in the labeling of the tables. The values represented in table B.18 represents peaks before EE and before DR.

The values presented in B.19 should align with the table provided below seasonal peak after EE and Before DR.

Table B.18: Duke Energy Kentucky System Seasonal Peak Load Forecast After EE, Before DR

	Summer			Winter		
Year	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.90%	797	64	8.70%
2019	849	-8	-0.90%	821	24	3.00%
2020	809	-40	-4.70%	742	-79	-9.60%
2021	838	29	3.60%	678	-64	-8.60%
2022	831	-7	-0.80%	710	32	4.70%
2023	834	3	0.40%	810	100	14.10%
2024	808	-26	-3.26%	748	-62	-8.29%
2025	810	2	0.24%	737	-11	-1.54%
2026	812	3	0.32%	738	1	0.14%
2027	812	0	-0.03%	740	2	0.27%
2028	812	0	0.02%	740	1	0.09%
2029	812	0	0.01%	739	-1	-0.13%
2030	822	10	1.19%	747	8	1.01%
2031	827	5	0.66%	749	3	0.34%
2032	831	4	0.46%	746	-3	-0.42%
2033	838	7	0.85%	755	9	1.20%
2034	844	5	0.64%	759	4	0.55%
2035	862	18	2.11%	774	15	1.90%
2036	872	10	1.16%	777	3	0.41%
2037	882	10	1.14%	779	1	0.18%
2038	892	10	1.08%	778	-1	-0.08%
2039	902	10	1.13%	798	20	2.53%
2040	910	8	0.85%	808	10	1.22%
2041	916	7	0.73%	808	0	-0.06%
2042	930	14	1.47%	813	6	0.69%
2043	942	12	1.24%	816	3	0.38%
2044	954	12	1.30%	818	1	0.14%
2045	965	11	1.09%	842	25	2.95%

(a) Difference between reporting year and previous year.

(b) Difference expressed as a percent of previous year.

Additionally, the values presented in B.13 are slightly overstated due to the double counting the impact of EE. The table below presents the correct values seasonal peak values before EE and before DR.

Table B.18: Duke Energy Kentucky System Seasonal Peak Load Forecast Before EE, Before DR

Year	Summer			Winter		
	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	(8)	-0.9%	821	24	3.0%
2020	809	(40)	-4.7%	742	(79)	-9.6%
2021	838	29	3.6%	678	(64)	-8.6%
2022	831	(7)	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	809	(25)	-3.0%	748	(62)	-7.7%
2025	812	2	0.3%	738	(10)	-1.4%
2026	816	4	0.5%	740	2	0.3%
2027	817	1	0.2%	743	3	0.4%
2028	819	2	0.2%	745	2	0.3%
2029	820	2	0.2%	746	0	0.1%
2030	832	11	1.4%	755	9	1.2%
2031	838	7	0.8%	759	4	0.5%
2032	844	5	0.6%	757	(2)	-0.2%
2033	852	8	0.9%	767	10	1.3%
2034	858	6	0.7%	772	5	0.6%
2035	876	19	2.2%	787	15	1.9%
2036	887	10	1.2%	790	3	0.4%
2037	897	10	1.2%	791	2	0.2%
2038	907	10	1.1%	791	(1)	-0.1%

2039	917	10	1.1%	811	20	2.5%
2040	924	7	0.8%	820	10	1.2%
2041	931	6	0.7%	820	(1)	-0.1%
2042	944	14	1.5%	825	6	0.7%
2043	956	12	1.2%	828	3	0.4%
2044	968	12	1.3%	829	1	0.1%
2045	978	10	1.1%	854	25	3.0%

(a) Difference between reporting year and previous year.

(b) Difference expressed as a percent of previous year.

PERSON RESPONSIBLE: Ibrar Khera

STAFF-DR-01-033

REQUEST:

Refer to the IRP, Appendix C, page 101. Explain whether customers with behind the meter generation are eligible for DSM programs.

RESPONSE:

Customers with behind the meter generation are eligible for DSM programs, provided they meet the specific DSM program's eligibility requirements.

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-034

REQUEST:

Refer to the IRP, Appendix C, page 101. Explain the historical and forecast budgets supporting the level of DSM included in the load forecast.

RESPONSE:

The first five-years of the DSM program budget forecast was based on the Company's 2024-2028 internal budget forecast, and future years applied a 2.5% inflation rate. Both savings and costs also include projected impacts associated with Inflation Reduction Act energy efficiency credits and tax credits during the 2024-2032 period.

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-035

REQUEST:

Refer to the IRP, Appendix C, page 101.

a. For each of the DSM programs listed, explain whether the specific budget allocated to the program and or the number of participating customers has been reached in in 2023 and year to date 2024.

b. For the purposes of load forecasting, explain whether each program was assumed to be fully subscribed and, if so, provide the maximum level of energy and capacity savings included in the forecasts.

RESPONSE:

a. Please see STAFF-DR-01-035(a) Attachment.

b. The Company considers a program fully subscribed when no additional participation can be achieved in the market. Therefore, for the purposes of load forecasting, the programs are not yet fully subscribed. However, each program's energy and capacity savings incorporated in load forecasting are based on participation projections that are informed by past program performance.

PERSON RESPONSIBLE: Tim Duff

Duke Energy Kentucky
2023 True Up: July 2022 - June 2023
Program Summary

Program	Fiscal Year 2022/2023 Actuals – Impacts: Annual KWH Net FR, @ Plant Total	Fiscal Year 2022/2023 Actuals – Impacts: Annual SKW Net FR, @ Plant Total	Fiscal Year 2022/2023 Actuals – Total Costs	Fiscal Year 2022/2023 Projected – Impacts: Annual KWH Net FR, @ Plant Total	Fiscal Year 2022/2023 Projected – Impacts: Annual SKW Net FR, @ Plant Total	Fiscal Year 2022/2023 Projected – Total Costs	% Achievement – Impacts: Annual KWH Net FR, @ Plant Total	% Achievement – Impacts: Annual SKW Net FR, @ Plant Total	% Achievement – Total Costs
Res									
Energy Efficiency									
Income Qualified Neighborhood	462,593	47	$ 571,412	371,558	93	$ 503,214	124.50%	51.07%	113.55%
Income Qualified Services	167,949	37	$ 239,784	274,833	63	$ 506,701	61.11%	58.52%	47.32%
My Home Energy Report	2,019,733	590	$ 31,477	1,702,322	480	$ 78,224	118.65%	122.78%	40.24%
Residential Energy Assessments	516,604	56	$ 187,280	748,439	84	$ 284,858	69.02%	66.66%	65.74%
Residential Smart $aver®	1,602,722	216	$ 787,360	2,302,375	198	$ 1,192,589	69.61%	108.70%	66.02%
Total	**4,769,600**	**945.6**	**$ 1,817,313**	**5,399,526**	**918.5**	**$ 2,565,587**	**88.33%**	**102.95%**	**70.83%**
Demand Response									
Peak Time Rebate Pilot Program	0	193	$ 242,753	0	194	$ 216,257	0.00%	99.48%	112.25%
Power Manager®	0	13,155	$ 835,517	0	24,526	$ 855,519	0.00%	53.64%	97.66%
Total	**0**	**13,348**	**$ 1,078,269**	**0**	**24,720**	**$ 1,071,776**	**0**	**54.00%**	**100.61%**
NonRes									
Energy Efficiency									
Business Energy Saver	1,683,070	271	$ 496,251	3,193,421	525	$ 771,723	52.70%	51.61%	64.30%
Smart $aver® Non-Residential	3,041,081	328	$ 503,612	6,926,586	1,019	$ 1,218,433	52.70%	32.19%	41.33%
Total	**4,724,152**	**599**	**$ 999,862**	**10,120,007**	**1,544**	**$ 1,990,156**	**46.68%**	**38.79%**	**50.24%**
Demand Response									
PowerShare®	0	11,848	$ 885,512	0	24,533	$ 851,383	0	48.29%	104.01%
Total	**0**	**11,848**	**$ 885,512**	**0**	**24,533**	**$ 851,383**	**0**	**48.29%**	**104.01%**
Cost Recovery									
Payment Plus			$ 169,808			$ 191,514			88.67%
Total			**$ 169,808**			**$ 191,514**			**88.67%**
Total	**9,493,752**	**26,741**	**$ 4,950,765**	**15,519,533**	**51,716**	**$ 6,670,417**	**61.17%**	**51.71%**	**74.22%**

Duke Energy Kentucky
July 2023 - June 2024 (Estimated)
Program Summary

	Fiscal Year 2023/2024 Actuals (est)*			Fiscal Year 2023/2024 Projected			% Achievement		
	Impacts			Impacts			Impacts		
Program	Annual KWH Net FR, @ Plant Total	Annual SKW Net FR, @ Plant Total	Total Costs	Annual KWH Net FR, @ Plant Total	Annual SKW Net FR, @ Plant Total	Total Costs	Annual KWH Net FR, @ Plant Total	Annual SKW Net FR, @ Plant Total	Total Costs
Res									
Energy Efficiency									
Income Qualified Neighborhood	574,114	57	$ 500,489	353,593	88	$ 512,928	162.37%	64.37%	97.58%
Income Qualified Services	127,122	29	$ 330,743	261,545	60	$ 748,845	48.60%	48.70%	44.17%
My Home Energy Report	12,562,648	3,698	$ 96,302	13,795,870	4,037	$ 275,858	91.06%	91.61%	34.91%
Residential Energy Assessments	776,394	85	$ 329,589	855,961	97	$ 286,985	90.70%	88.32%	114.85%
Residential Smart $aver®	1,025,955	161	$ 537,349	1,565,180	113	$ 520,248	65.55%	142.72%	103.29%
Total	**15,066,233**	**4,030.2**	**$ 1,794,473**	**16,832,149**	**4,394.3**	**$ 2,344,863**	**89.51%**	**91.71%**	**76.53%**
Demand Response									
Peak Time Rebate Pilot Program	0	179	$ 83,774	0	180	$ 216,000	0.00%	99.50%	38.78%
Power Manager®	0	11,465	$ 857,581	0	13,515	$ 1,104,092	0.00%	84.84%	77.67%
Total	**0**	**11,645**	**$ 941,355**	**0**	**13,695**	**$ 1,320,092**	**0**	**85.03%**	**71.31%**
NonRes									
Energy Efficiency									
Business Energy Saver	2,748,713	481	$ 804,361	3,945,006	662	$ 879,517	69.68%	72.60%	91.45%
Smart $aver® Non-Residential	9,008,509	1,183	$ 901,329	9,597,343	1,784	$ 2,090,665	52.70%	66.31%	43.11%
Total	**11,757,221**	**1,664**	**$ 1,705,690**	**13,542,350**	**2,446**	**$ 2,970,183**	**86.82%**	**68.02%**	**57.43%**
Demand Response									
PowerShare®	0	6,052	$ 739,395	0	11,251	$ 1,063,284	0	53.79%	69.54%
Total	**0**	**11,179**	**$ 739,395**	**0**	**11,251**	**$ 1,063,284**	**0**	**99.37%**	**69.54%**
Cost Recovery									
Payment Plus			$ 179,569			$ 191,478			93.78%
Total			**$ 179,569**			**$ 191,478**			**93.78%**
Total	**26,823,455**	**28,518**	**$ 5,360,482**	**30,374,499**	**31,786**	**$ 7,889,900**	**88.31%**	**89.72%**	**67.94%**

* Fiscal year 2023-2024 results are still under review and should not be considered final

STAFF-DR-01-036

REQUEST:

Refer to the IRP, Appendix C, pages 106–110. Explain whether Duke Kentucky has examined the differences in potential Low-Income Services program need and participation for the poverty groups that are between 100 percent below the federal poverty level up to the federal poverty level, and the group that falls between 100 percent and 200 percent below the federal poverty level.

RESPONSE:

The company has not explored the differences in program needs based upon poverty levels as outlined in the data request. The company does not currently collect or possess customer income level to perform this analysis.

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-037

REQUEST:

Refer to the IRP, Appendix C, pages 106-110 and pages 116–117.

a. Explain the extent to which Duke Kentucky works with non-profit groups, such as Habitat for Humanity, or any other housing construction/renovation group to enhance the energy efficiency of the housing and appliances.

b. For the Low-Income Neighborhood Program, in instances where the "at least 50 percent of the households at or below 200 percent of the federal poverty guidelines" threshold is almost (but not quite) met within a given geographic boundary, explain what actions, if any, Duke Kentucky takes to assist households in that area.

c. For the Low-Income Neighborhood Program, explain whether there is a minimum number of household structures necessary to define a neighborhood or if Duke Kentucky will gerrymander street boundaries to create a neighborhood that fits the poverty threshold.

RESPONSE:

a. For Neighborhood Energy Saver, the program team would work with Habitat for Humanity to increase awareness and promote the program in a particular neighborhood. The program team could also work with the housing authority to explain & promote the program within the selected neighborhood and assist in gaining approval for rental properties.

b. The Company will expand or limit neighborhood boundaries to ensure that a least 50 percent of the households are identified as at or below 200% federal poverty guidelines.

   - Neighborhoods are typically defined by larger roads or natural environments like rivers, etc.
   - Multifamily homes are removed from the program as they are not currently eligible and will be referred to the Residential Smart $aver® - multifamily portion of the program.
   - Commercial buildings that may reside in the "neighborhood" are also removed from qualification.

   Customers in neighborhoods that do not meet the minimum 50% criteria are eligible for Home Energy Assessments and are provided referrals for Residential Smart $aver® or Weatherization if additional support is needed and the customer has indicated that they are income eligible.

c. Yes, there is a minimum number of household structures necessary to define a neighborhood. A neighborhood size is approximately 500 – 1,500 households. However, Duke Energy Kentucky can and will gerrymander street boundaries to create a neighborhood that fits the poverty threshold if necessary.

PERSON RESPONSIBLE: Tim Duff

Duke Energy Kentucky
Case No. 2024-00197
STAFF's First Set Data Requests
Date Received: August 13, 2024

STAFF-DR-01-038

REQUEST:

Refer to the IRP, Appendix C, page 108. Explain what Tier 2 services are included in the program that are in addition to Tier 1 services.

RESPONSE:

Tier Two services are as follows:

- All Tier One Services and Air Sealing Measures plus:
- Additional cost-effective measures using the NEAT audit where the energy savings pay for the measure over the life of the measure as determined by a standard heat loss/economic calculation. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, and floor insulation.
- Heating system and air conditioning tune and clean and/or repair. Heating and cooling systems can be replaced if the repair cost is greater than $600.

PERSON RESPONSIBLE: Tim Duff