EVERGY METRO

INTEGRATED RESOURCE PLAN

2020 ANNUAL UPDATE

MARCH 2020

PUBLIC

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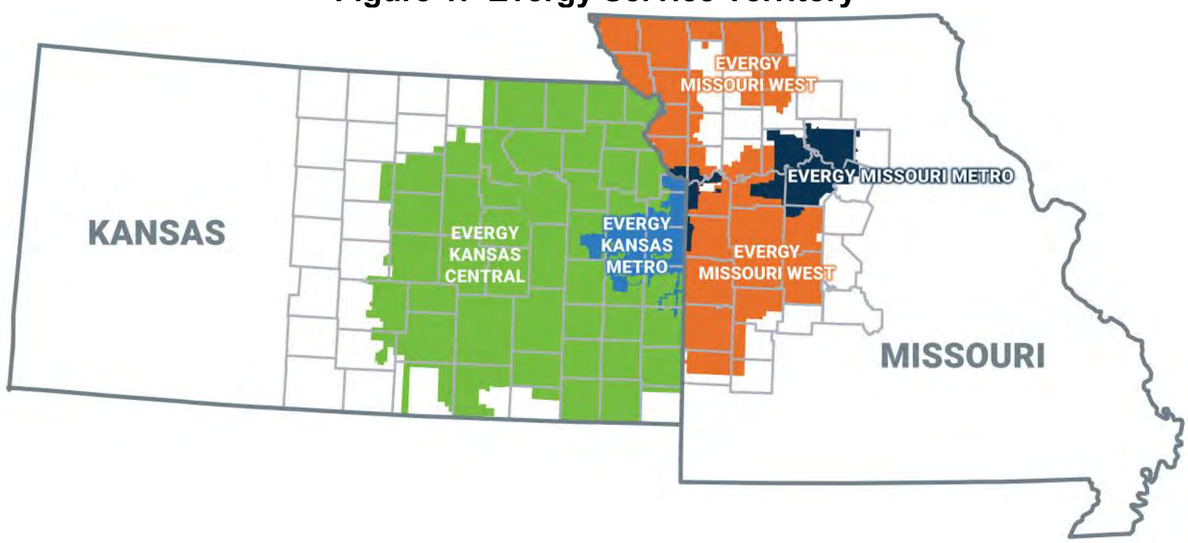
SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Evergy Metro (or "Company") is an integrated, mid-sized electric utility serving the metropolitan region surrounding the Kansas City, Missouri metropolitan area including customers in Kansas and Missouri. A map of the entire Evergy service territory which includes Evergy Metro is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Evergy Metro is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2019 data.

Table 1: Evergy Metro Customers, Retail Sales and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Metro Missouri	291,626	8,404,298	1,700
Evergy Metro Kansas	262,344	6,432,097	1,766
Evergy Metro	553,970	14,836,394	3,441

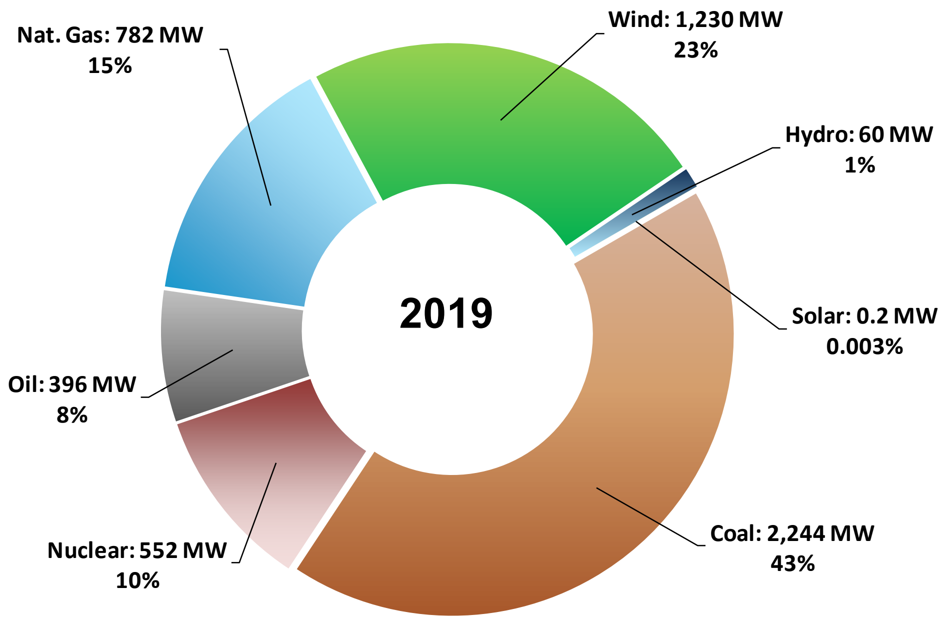
Evergy Metro owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Three recent renewable generation projects that Evergy procured are Expedition Wind, Jayhawk Wind, and Ponderosa Wind. The 199 MW Expedition Wind facility is expected to reach commercial operations in the first quarter of 2021, Evergy Metro's 155 MW portion of the 192 MW Jayhawk Wind facility is expected to reach commercial operations in the 4th quarter of 2021, and Evergy Metro's 178 MW portion of the 200 MW Ponderosa Wind facility is expected to reach commercial operations in the 4th quarter of 2020. Table 2, Figure 2, and Figure 3 reflect Evergy Metro's generation assets operating in 2019.

Table 2: Evergy Metro Capacity and Energy by Resource Type

Capacity By Fuel Type	Capacity (MW)	% of Total Capacity	Annual Energy (MWh)	% of Annual Energy
Coal	2,244	42.6%	10,968,732	53.8%
Nuclear	552	10.5%	4,346,447	21.3%
Nat. Gas and Oil	1,178	22.4%	339,127	1.7%
Wind	1,230	23.4%	4,352,080	21%
Hydro	60	1.1%	386,147	1.9%
Solar	0.2	0.003%	140	0.001%
Total	5,265	100.0%	20,392,533	100.0%

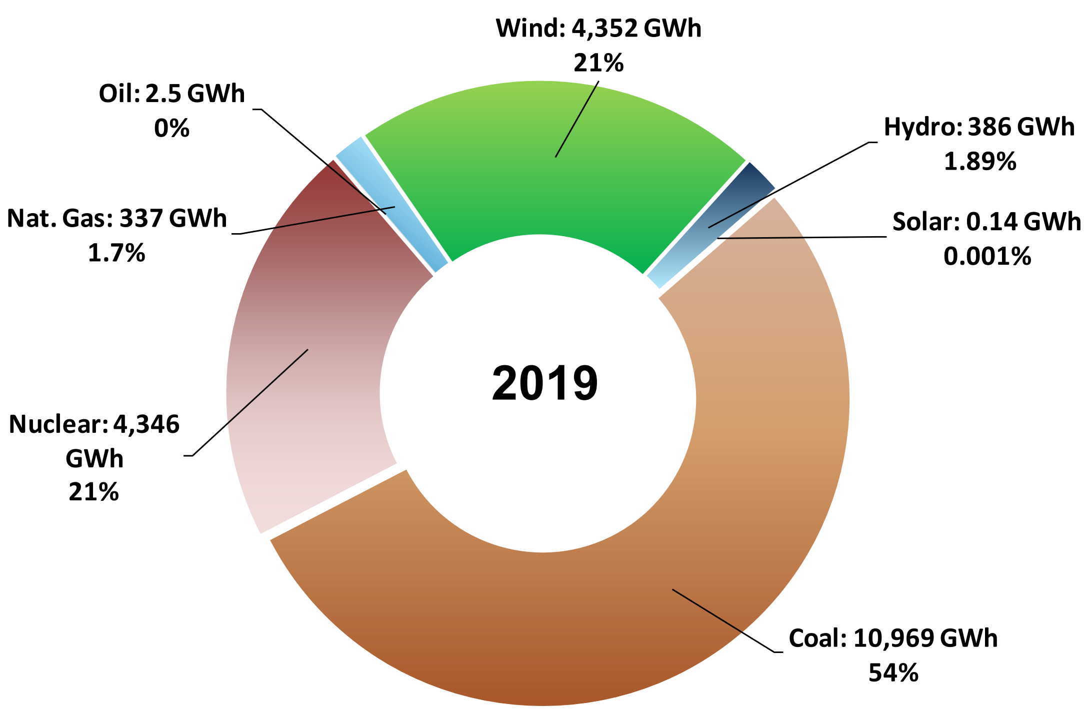
* Wind capacity is based upon nameplate

Figure 2: Evergy Metro Capacity by Resource Type



Note: Wind capacity is based upon nameplate

Figure 3: Evergy Metro Energy by Resource Type



1.2 CHANGES FROM THE 2018 TRIENNIAL IRP

On April 2nd, 2018, Kansas City Power and Light ("KCP&L") submitted the triennial compliance filing related to Chapter 22 of the Missouri Public Service Commission ("Commission") regulations concerning the Company's Electric Utility Resource Planning. The triennial compliance filing made in Case No. EO-2018-0268 consisted of eight sections of material including the "KCP&L Preferred Resource Plan" identified in "Volume 7, Resource Acquisition Strategy Selection". Based in part upon current Missouri RPS rule requirements, the Preferred Resource Plan included 13 MW of solar additions and 178 MW of wind additions from KCP&L's portion of two power purchase agreements (PPAs) executed in 2017. The Preferred Resource Plan also included retiring 334 MW of coal generation at Montrose Station by 2019.

In March 2019, the Company was expected to file an Integrated Resource Plan annual update required by Commission Rule 4 CSR 24-22.080(3). Because of uncertainty regarding the status of the Missouri Energy Efficiency Investment Act ("MEEIA"), Evergy Metro and the MPSC Staff agreed it would be appropriate for the Commission to grant a variance from filing the 2019 Integrated Resource Plan annual update. The Commission granted the requested variance in MPSC File No. EO-2019-0245 which became effective on August 17, 2019.

The Evergy Metro (formerly KCP&L) business plan or acquisition strategy had become materially inconsistent with the Preferred Resource Plan filed in the 2018 Triennial compliance filing. Therefore, on December 27th, 2019, pursuant to 4 CSR 240-22.080(12), the Company made notification of the material inconsistency of the triennial compliance filing, Case No. EO-2018-0268, to the Commission and Parties. The singular material change from the April, 2018 Preferred Resource Plan was with respect to wind resource additions, all other components including future solar additions, DSM levels, and unit retirements remained consistent with the 2018 Preferred Resource Plan.

Since the filing of the 2018 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the

Preferred Plan and associated Resource Acquisition Strategy identified in 2018 Triennial IRP continue to be the company's path forward. The information and forecasts that have been updated for the 2020 Annual Update include:

- Supply-side cost options
- Load forecasts
- Fuel forecasts
- Proposed and potential environmental regulations
- Demand-Side Management program levels

1.3 2020 ANNUAL UPDATE PREFERRED PLAN

1.3.1 INTEGRATED RESOURCE PLAN OVERVIEW

Evergy's integrated resource planning experience spans many decades with its most recent triennial preferred plans filed for both KCP&L and GMO (now Evergy Metro and Evergy Missouri West, respectively) in 2018 ("2018 IRP"). Between triennial IRP filings, Commission regulations require annual updates reflect any material changes to the triennial filing and/or confirmation of the continued applicability of the originally filed preferred plan. This document includes the annual update filing for 2020 ("2020 Update") that, consistent with Commission regulations, outlines material changes to the 2018 IRP. Note that this 2020 Update incorporates the change in preferred plans filed in December 2019 that included a delay in the retirement of Lake Road Unit 4/6 and the addition of 532 MW of wind generation for Evergy Metro and Evergy Missouri West. The only material change in the 2020 preferred plan is the anticipated addition of 500 MW of renewable generation (modeled as solar) in 2023 for Evergy.

	2018 IRP	2019 Change in Plan Filing	2020 Annual Update
Retirements	Lake Road 4/6 - Dec, 2019	Lake Road 4/6 - Dec, 2024	Lake Road 4/6 - Dec, 2024
Wind Additions	444 MW, 2018/2019	532 MW 2020/2021 (Metro and Mo West)	660 MW 2020/2021 (Evergy)
Solar Additions	23 MW, 2028	23 MW, 2028	23 MW, 2028 500 MW 2023 (Evergy)
DSM	RAP*-	RAP*-	RAP*-
* Realistic Achievable Potential			

While this 2020 Update does not reflect any material change to plant retirements compared to the 2018 IRP preferred plan, Evergy increasingly believes key critical uncertainties that support the evaluation and selection of the preferred plan have changed and will continue to change. Most significantly, the forward forecast for natural gas prices and future carbon restrictions, which represent two of the most critical uncertainties and assumptions in this integrated resource planning analysis, continue to trend in directions that could materially change our view of the preferred plan. Natural gas prices have continued to remain relatively low over the last several years despite prior and current independent gas price forecasts that have indicated expected price increases. Further, we increasingly believe carbon restrictions are likely over the 20-year planning period and our current view is that such carbon restrictions are slightly more likely than not. The combination of these factors could result in a preferred plan that would require a larger magnitude and faster pace of coal generation retirements and the need to recover the remaining investment in these retired facilities and secure additional renewable generation (solar and wind), natural gas generation and/or storage to secure the energy needs of the region

As a result of the GPE/Westar merger in mid-2018 and the MPSC waiver of the 2019 Annual Update, this 2020 Update is the first update to include an evaluation of the combined Evergy Metro, Evergy Missouri West, and Evergy Kansas Central systems.

Given that the IRP to be filed in April 2021 will be the first full IRP for Evergy and key uncertainties are trending towards potentially significant changes to the Evergy supply portfolio, Evergy is currently developing a plan to obtain input from interested stakeholders during the 2021 IRP development. In addition, Evergy will use an all-source Request for Proposal to support the 2021 IRP analysis and to further refine the assumptions used to identify the 500 MW renewable addition.

In summary, this 2020 Update is consistent with the Commission’s integrated resource planning regulations and highlights changes to the preferred plan filed in our 2018 IRP. However, given an evolving energy landscape, the importance of key critical uncertainties in the resource planning process and the formation of Evergy, we believe stakeholder outreach is important in the development of our 2021 triennial IRP and we will use the balance of 2020 and the first quarter of 2021 to develop a preferred plan that best meets the needs of our customers and communities.

SECTION 2: LOAD ANALYSIS AND LOAD FORECASTING UPDATE

2.1 CHANGES FROM THE 2018 TRIENNIAL IRP

Several inputs to the load forecasting models were updated for this filing compared to the 2018 Triennial IRP.

- Historical data for customers, kwh and $/kwh: ending June 2019 vs ending June 2017
- DOE forecasts of appliance and equipment saturations and kwh/unit: 2019 vs 2017
- Class models in the 2020 Metro Update filing are the same as the 2018 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial.
- The Company also re-evaluated the output elasticity used in the commercial and industrial models and the elasticity used in the residential model. Adjustments made were to improve the model fit.
- Company utilized EPRI electric vehicle study within its modeling for 2020 Update filing.
- EIA West North Central Commercial end-use saturations were calibrated to the Metro 2016 potential study C&I saturation survey results.
- Commercial end-use intensity / sq. ft. from the EIA West North Central division were calibrated to the conditional demand outputs from the 2016 Metro potential study.
- Low and High bands were generated using low case and high case economic scenarios as in the past, but instead of estimating separate models, the forecasts were simulated using the base model coefficients with the low and high case forecasted inputs.

Table 3, Table 4, and Table 5 below show a lower forecast for both peak and energy for the 2020 Update compared to the 2018 Triennial IRP. Below are the primary reasons for the change in forecast.

- There are several changes from the Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) to the 2019 AEO resulting from updates to end-use efficiency and saturation estimates. The EIA's updates impact to the 2020 IRP Update short-term growth rate is higher than the 2018 Triennial IRP forecast due to EIA rebasing Residential to the 2015 RECS (Residential Energy Consumption Survey) vs. the 2009 RECS, resulting in more weight on the cooling and heating variable which are more positive short-term than in 2018. The long-term growth rate is slightly lower comparted to 2018 due to lower Commercial intensity estimates long-term. Below is a summary of the impact by class.

- Residential: Total residential intensity changed very little from the 2017 AEO. This is the first EIA release based on the 2015 RECS; prior releases used the 2009 RECS. Estimates based on the 2015 RECS resulted in higher levels of intensity for cooling and electric space heating, but lower levels of base load intensity. The growth trajectory (slope) for heating intensity was essentially unchanged from the 2017 AEO, while the cooling intensity trajectory was slightly more positive in the near term (2020-2024) compared to the 2017 AEO. The slope of the base load forecast in the 2019 AEO is slightly more negative in the near term (2020-2024) and slightly less negative after. The difference in base load is explained by the updated estimates of miscellaneous intensity based on the 2015 RECS.
- Commercial: Total commercial intensity trajectory declined from the 2017 AEO, with growth being slightly slower 2020-2024 and significantly slower thereafter. The end-uses contributing to the change from the 2017 AEO intensity are primarily Heating and Lighting in the near-term, Heating and Miscellaneous in the long-term. Heating and Lighting efficiency is forecasted to increase at a faster rate than previously forecasted (causing lower intensity), while Miscellaneous intensity is expected to rise more rapidly in the near-term and then flatten after 2025.

- Industrial: Overall intensity and end-use intensity for industrial were largely unchanged.
- In the 2020 IRP Update forecast, the EIA end-use equipment intensity for Commercial was calibrated to company-specific intensity / sq. ft. estimates (this was not done in previous forecasts because these estimates first became available as part of the 2016 potential study); these estimates reveal more of Commercial usage to be lighting than is estimated by the EIA for the West North Central division. The efficiency forecast for lighting is far more aggressive than other end-uses. The net effect of this calibration is downward pressure on the Commercial forecast compared to previous forecasts that used EIA intensity estimates directly.

Table 3: Evergy Metro Mid-Case Annual NSI and Peak Forecast ** Confidential**

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Table 4: Load Forecasts – 2020 Annual Update Vs. 2018 Triennial IRP ** Confidential**

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Table 5: Energy Forecasts – 2020 Annual Update Vs. 2018 Triennial IRP ** Confidential**

C

SECTION 3: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

3.1 FUEL AND EMISSION FORECAST CHANGES FROM THE 2018 TRIENNIAL IRP

The fuel and emissions forecasts have been updated for the 2020 Annual Update. Note that except for the low gas price forecast that was capped at the recent 5-year historical average, the methodology used in determining the forecast range has not changed from the 2018 Triennial IRP. The natural gas and CO_2 forecast data is presented in graphical and tabular form on the next pages.

Table 6: Natural Gas Forecasts - 2020Annual Update Vs. 2018 Triennial IRP ** Confidential**

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Table 7: Natural Gas Forecasts - 2020 Annual Update Vs. 2018 Triennial IRP Table Confidential****

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Table 8: CO_2 Forecast - 2020 Annual Update Vs. 2018 Triennial IRP ** Confidential**

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Table 9: CO_2 Forecast - 2020 Annual Update Vs. 2018 Triennial IRP Table ** Confidential**

C

The following two tables provide the sources of the fuel and emission forecasts reflected in the above charts.

Table 10: Natural Gas and CO_2 Forecast Sources

Forecast Source	Natural Gas	CO_2
IHS Markit	x	x
Energy Information Administration	x	
S&P Global Platts	x	x
Energy Ventures Analysis	x	

3.1.1 SUPPLY-SIDE TECHNOLOGY RESOURCE OPTIONS

Supply-side technology candidates included in integrated resource analysis in the 2020 Annual Update are shown in Table 11 below. The cost and operating data sources for these technologies were obtained from the U.S. Energy Information Administration's (EIA) 2019 Annual Energy Outlook, and recently obtained market intelligence. These supply-side options include combustion turbine, combined cycle, wind, and solar generation options.

Table 11: Supply-Side Technology Options

	Combustion Turbine*	Combined Cycle*	Wind	Solar^
Capital Cost ($/kW)	$753	$1,062	$1,487	$1,200
Fixed O&M ($/kW)	$30.92	$27.65	$14.27	$9.00
Variable O&M ($/MWh)	$11.58	$3.79	$1.20	$0.00

*** Includes Nat Gas Transport**
^ Before Investment Tax Credit
Capital Costs include Estimated Interconnection Costs

3.1.2 LIFE ASSESSMENT & MANAGEMENT PROGRAM

The 2020 Annual Update included an update of the Life Assessment and Management Program (LAMP) data for the Evergy Metro coal-fired generating units. The LAMP program was developed in the late 1980's for identifying, evaluating, and recommending improvements and special maintenance requirements necessary for continued reliable operation of Evergy Metro coal-fired generating units.

SECTION 4: TRANSMISSION AND DISTRIBUTION UPDATE

4.1 CHANGES FROM THE 2018 TRIENNIAL IRP

Transmission and Distribution-related changes and updates are provided below:

4.1.1 RTO EXPANSION PLANNING

Evergy Metro's assessment of RTO expansion plans is an ongoing process that occurs throughout the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from Evergy Metro staff, and review and approval of final plan reports. All transmission projects for the Evergy Metro service territory are included in SPP's annual Transmission Expansion Plan Report and Project List. By meeting the performance standards established for transmission planning, the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for the Company. These documents are attached as Appendix A 2020 SPP Transmission Expansion Plan Report.pdf and Appendix A1 2020 SPP Transmission Expansion Plan Project List.xls.

4.1.2 ADVANCED DISTRIBUTION TECHNOLOGIES DISCUSSION

Having completed the SmartGrid Demonstration project in 2015, Evergy Metro has been implementing targeted Advanced Distribution Technologies (ADT).

Main initiatives in the near-term ADT plan include:

- Fault Location Isolation and Supply Restoration (FLISR) utilization
- Advancing Fault Location functionality with the new Outage Management System (OMS).
- We are piloting new advances in Communicating Faulted Circuit Indicators (CFCIs) with embedded communication modules, allowing for quick installation and potentially lower cost.
- Replace “2G” and “3G” vintage distribution end-device cellular communications equipment.
- Install “4G” and pilot “5G” distribution end-point communications equipment.
- Develop a multi-year Grid Modernization Roadmap

4.1.2.1 Fault Location Isolation and Supply Restoration (FLISR)

Evergy Metro is piloting two schemes for FISR: one using peer-to-peer communications between smart switching devices and a second one using a closed-loop hybrid of centralized and local control.

4.1.2.1.1 FLISR Using Peer-to-Peer (PTP) Communications

The Company completed a pilot (Phase 1) for FISR with PTP communications for proof of concept located in Roeland Park, Kansas.

The switching devices chosen for this pilot are S&C Electric’s Intellirupter Pulseclosers. PTP is a term meaning that there are specific communications between the switches on the feeder so these intelligent devices share information before performing any automated switching operations. Switches will be placed at middle points on adjacent circuits as well as the normally open switch points between these circuits.

In the FLISR pilot, the Intelliteam system and the PTP communications will automatically identify a faulted circuit section (without requiring a human patrol), perform switching to isolate the faulted section and perform switching to restore sections not affected by the fault.

After the automated switching is completed, the Intelliteam system will communicate the results via cellular communications to Company operators informing them of the faulted section and the restoration switching already performed. Dispatchers will then have information to dispatch crews directly to the faulted section to identify the physical problem and make repairs. After repairs are completed, dispatchers can remotely switch the system back to its normal configuration without requiring a field crew to perform the switching.

The initial pilot (Phase 1) consisted of multiple S&C IntelliRupters in the aforementioned Kansas location. This technology has operated 5 times since March 2017. Normally reconfigurations take less than 2 seconds and we currently have these assets set to be manually configured back to normal, ensuring the safety of personnel. A second phase of pilots is being evaluated against other technologies and engineering practices.

4.1.2.1.2 Closed-Loop FLISR Scheme

The Company can support this through our standardized field asset installations. The Company is working through the communications and programming functions of the controller for this Closed-Loop FLISR Scheme pilot (Phase 1).

A centralized FLISR engine will be used to drive the primary functions of our Intelligent End Devices (IEDs). These functions include SCADA commands, automated FLISR actions, circuit / substation parameters and safety needs such as hold cards. In order to enable a hybrid approach, the IED will consume remote data while taking on some of the responsibility to adjust circuit protection settings, trip cycles and switching functions. This allows IEDs to have a subset of safe operational capabilities should communications go out.

Closed-Loop systems require little operator interaction during FLISR events. This allows the FLISR system to run quickly and effectively based on engineered algorithms. Operators will have ultimate authority over the system and will be able to disable and enable FLISR as needed.

4.1.2.2 OMS Fault Location Functionality

The supplier of the Company's OMS system has an advanced application for predicting fault location. To properly complete this action, the OMS will need circuit impedance and communicating field equipment data to predict sections of a feeder where a fault may be physically located. One method for better fault location accuracy is installing additional fault sensors (such as communicating faulted circuit indicators or communicating switches) on the circuit while another method is centered around circuit and data modeling plus smart meter integration.

The Company's selected fault location solution is circuit and data modeling. Benefits anticipated from Fault Location prediction are mainly reduced patrol time for field crews. Dispatchers can direct field crews to focus on predicted faulted sections vs. patrolling an entire circuit to identify a fault.

No specific timeline has been established for this, but we are working to validate the system model within OMS and aggregate the required field data, helping establish requirements for accurate fault location. Success is dependent on OMS system capability plus successful integration and testing of the new web platform.

4.1.2.3 Communicating Faulted Circuit Indicator (CFCI)

Evergy Metro is perpetually evaluating emerging CFCI technologies and installing where enhancements benefit grid resiliency and reliability.

Dispatchers now have the ability to receive CFCI alarms and activity in OMS. Using the OMS One-line diagram, Operators use CFCIs while troubleshooting an outage. This greatly enhances the "visibility" and usefulness of CFCIs to dispatchers.

CFCIs are also anticipated to be a cost-effective way to enhance the Fault Location functionality discussed previously. Although CFCIs cannot perform switching operations, they can enhance the effectiveness of dispatching and manual switching. It should be noted that we have installed 682 CFCIs in the Evergy Metro service territory.

Vendor development of CFCI has been slow to progress but has recently accelerated due to industry feedback. In the near future, we are looking to install CFCIs that have better data reads, are powered via a current transformer, and support imbedded 4G/5G network connectivity

4.1.2.4 2G and 3G Cellular Communications Replacement

Evergy Metro has cellular-based communications to field devices that utilize AT&T 2G and 3G generation communications. As planned, AT&T began to retire its 2G network in early 2017 and has issued notification of 3G retirement in 2021. The Company is replacing all critical endpoints that are immediately impacted by the retirements with 4G cellular or private cellular, starting in 2016. Additional replacements of less critical devices will continue under standard resource allocation models.

4.1.2.5 4G and 5G Cellular Communications Pilot

Evergy Metro's cellular communications provider recently introduced a series of endpoint devices using "4G" cellular communications. The Company has standardized to this equipment and started installing field equipment in 2016.

We are also evaluating the use case for 5G networks with utility IEDs. Currently, the backend carrier system support for 4G and 5G can utilize the same hardware (i.e., 4G and 5G are complementary networks). We suspect that 4G has a potential sunsetting date after 2040.

4.1.2.6 Develop a Multiyear Distribution Automation Roadmap

Evergy Metro developed a framework of potential scenarios for a multiyear Grid Automation Roadmap in 2016.

Following the completion of the merger with Westar, the new combined company is now developing a broader grid modernization roadmap which builds upon the aforementioned roadmap and will include operational aspects across the entire Company.

SECTION 5: DEMAND-SIDE RESOURCE ANALYSIS UPDATE

5.1 MEEIA CYCLE 3 2020-2022 PROGRAMS

Since the 2018 Triennial IRP filing, Evergy Missouri Metro has filed an application to implement its third MEEIA cycle for the Company. After extensive review with external parties, the Company made modifications to the plan to address many of the suggestions and recommendations made by the parties. This version of the MEEIA 3 plan was modeled in the IRP analysis. In December 2019, the Commission approved the Company's original MEEIA cycle 3 filing, however, it was too late in the IRP analysis to make this change. The impacts for the modified MEEIA Cycle 3 plan replace the impacts for the 2020-2022 program years from the 2018 triennial IRP. Table 12 and Table 13 below shows the annual cumulative demand and energy savings of the modeled MEEIA cycle 3 plan and the approved MEEIA cycle 3 savings.

Table 12: Evergy Missouri Metro Cumulative Demand Savings (MW) from MEEIA 3

Year	MEEIA 3 APPROVED	MEEIA 3 IRP MODEL
2020	27	37
2021	43	47
2022	64	63
2023	55	40
2024	56	44
2025	56	43
2026	55	43
2027	54	41
2028	54	39
2029	54	37
2030	49	33
2031	36	25
2032	21	15
2033	13	8
2034	10	5
2035	8	3
2036	8	2
2037	7	2
2038	5	1
2039	3	1

Table 13: Evergy Missouri Metro Cumulative Energy Savings (MWh) from MEEIA 3

Year	MEEIA 3 APPROVED	MEEIA 3 IRP MODEL
2020	37,205	37,420
2021	76,529	71,381
2022	138,839	128,336
2023	153,606	141,628
2024	162,461	156,467
2025	155,884	155,652
2026	150,735	153,357
2027	148,072	149,477
2028	145,912	144,372
2029	145,719	140,300
2030	138,273	131,451
2031	120,478	114,675
2032	92,362	86,196
2033	67,286	58,318
2034	49,979	37,312
2035	36,095	23,032
2036	26,331	15,341
2037	18,100	8,579
2038	12,952	5,167
2039	9,433	4,365

5.2 CHANGES FROM THE 2018 TRIENNIAL IRP

The scenarios for the 2020 Annual Update were updated from the 2018 Triennial preferred plan to reflect the modified MEEIA cycle 3 plan. Beginning Jan 1, 2023, the incremental annual energy and demand impacts are the same as the preferred plan filed in the 2018 Triennial IRP. Table 14 and Table 15 shows the annual cumulative energy and demand impacts for the MAP, RAP and RAP- scenarios for Evergy Missouri Metro. Evergy Kansas Metro is not affected by MEEIA programs, thus there is no change since the 2018 triennial IRP.

The IRP process takes the annual program potential and spreads the incremental savings across each year (i.e. not all new participants or installations are immediately providing savings on January 1st). The installations are spread equally throughout the year. The delayed installations lowered the expected first year savings of any given installation/program participant, but the total savings are still achieved over the life of the measures.

Table 14: DSM Annual Cumulative Demand Savings (MW)

Year	RAP-	RAP	MAP
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	91	121	151
2024	101	135	169
2025	112	149	186
2026	123	163	204
2027	134	177	221
2028	144	192	239
2029	153	203	252
2030	161	213	266
2031	167	221	276
2032	174	229	286
2033	179	237	295
2034	185	244	306
2035	191	252	317
2036	197	260	328
2037	203	267	338
2038	207	273	348
2039	211	279	356

Table 15: DSM Annual Cumulative Energy Savings (MWh)

Year	RAP-	RAP	MAP
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	41,125	53,922	69,804
2024	73,505	96,214	124,174
2025	106,180	138,901	179,005
2026	137,097	179,267	230,839
2027	168,632	220,441	283,610
2028	200,905	262,608	337,671
2029	237,284	309,377	399,460
2030	276,477	359,938	469,108
2031	316,884	412,102	540,432
2032	358,148	465,428	613,455
2033	388,911	505,564	669,539
2034	419,775	545,838	726,388
2035	448,177	582,819	779,117
2036	478,194	621,966	834,783
2037	506,963	659,473	888,360
2038	529,618	688,855	931,510
2039	548,763	714,394	967,851

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2018 TRIENNIAL IRP

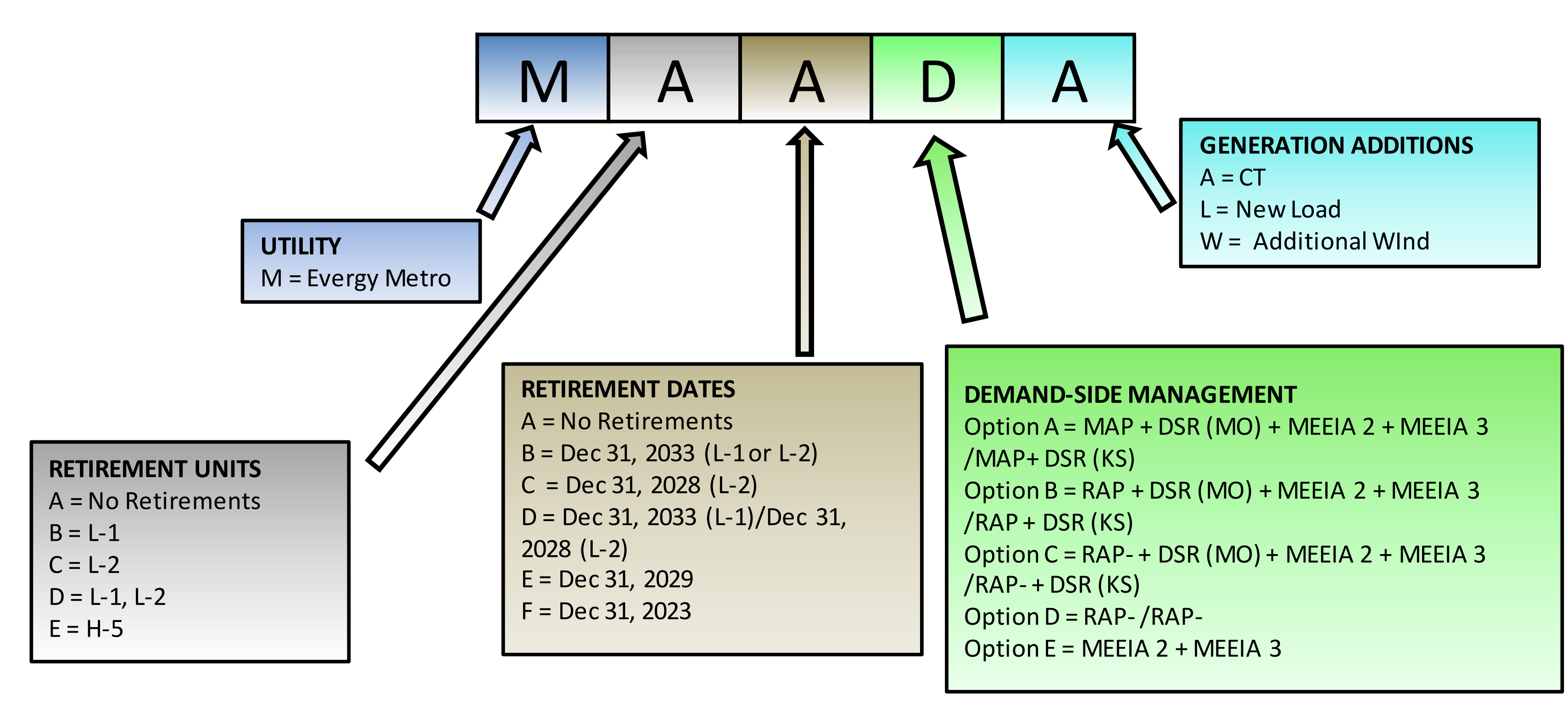
Since the filing of the 2018 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2018 Triennial IRP continue to be the company's path forward. The information and forecasts that have been updated for the 2020 Annual Update include:

- Supply-side cost options
- Load forecasts
- Fuel forecasts
- Proposed and potential environmental regulations
- Demand-Side Management program levels

6.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

Alternative Resource Plans (ARPs) were developed using a combination of supply-side resources, demand-side resources, various resource addition timings, as well as generation retirement options and timings. The plan-naming convention utilized for the ARPs developed is shown in Table 16 and an overview of the ARPs is shown in Table 17 and Table 18 below:

Table 16: Alternative Resource Plan Naming Convention



Definitions:

L-1: LaCygne-1	**MEEIA: Missouri Energy Efficiency Investment Act Cycle II**	**MAP: Maximum Achievable Potential**
L-2: LaCygne-2	**RAP: Realistic Achievable Potential**	**RAP-: Realistic Achievable Potential Minus**
H-5: Hawthorn-5	**CT - Combustion Turbine**	**DSR: Demand-Side Rates**

Table 17: Alternative Resource Plan Overview

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
MAAAA	MAP + DSR (MO) /RAP- + DSR (KS)	No Retirements	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MAACA	RAP- + DSR (MO) /RAP- + DSR (KS)	No Retirements	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MAACL	RAP- + DSR (MO) /RAP- + DSR (KS)	No Retirements	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	Add New Load
MAAEA	MEEIA 2 + MEEIA 3	No Retirements	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MBBBA	RAP + DSR (MO) /RAP + DSR (KS)	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MBBCA	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MBBCL	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	Add New Load 216 CT in 2038
MBBCW	RAP- + DSR (MO) /RAP + DSR (KS)	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	Add 100 MW Wind

Table 18: Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
MBBDA	RAP- /RAP-	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MBBEA	MEEIA 2 + MEEIA 3	LaCygne-1: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	216 CT in 2036 216 CT in 2039
MBFCA	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-1: Dec 31, 2023	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MCBCA	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-2: Dec 31, 2033	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MCCCA	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-2: Dec 31, 2028	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MDDCA	RAP- + DSR (MO) /RAP- + DSR (KS)	LaCygne-1: Dec 31, 2033 LaCygne-2: Dec 31, 2028	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None
MEECA	RAP- + DSR (MO) /RAP + DSR (KS)	Hawthorn-5: Dec 31, 2029	Solar: 13 MW	Wind: 377 MW (2021) 30 MW (2022)	None

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the Evergy Metro forecast of capacity balance over the twenty-year planning period for each of the Alternative Resource Plans outlined above. These capacity forecasts include renewable and generation additions. The capacity for existing wind facilities is based on SPP's criteria for calculating wind net capability using actual generation or wind data.

6.3 REVENUE REQUIREMENT

For each of the Alternative Resource Plans developed, integrated analysis yielded an expected value of the Net Present Value of Revenue Requirement shown in Table 19 below:

Table 19: Twenty-Year Net Present Value Revenue Requirement

Rank	PLAN	NPVRR ($MM)	DELTA
1	MAACA	$20,397.30	$0.00
2	MCBCA	$20,414.87	$17.57
3	MBBCA	$20,414.90	$17.59
4	MBFCA	$20,425.61	$28.31
5	MEECA	$20,429.95	$32.64
6	MCCCA	$20,442.80	$45.49
7	MBBCW	$20,443.98	$46.67
8	MBBBA	$20,445.60	$48.30
9	MEGCA	$20,453.99	$56.68
10	MDDCA	$20,466.33	$69.03
11	MBBDA	$20,478.84	$81.54
12	MAAEA	$20,530.27	$132.96
13	MAAAA	$20,571.06	$173.76
14	MBBEA	$20,584.21	$186.90
15	MAACL	$20,913.06	$515.75
16	MBBCL	$20,945.69	$548.38

6.4 PERFORMANCE MEASURES

A summary tabulation of the expected value of all performance measures is provided in Table 20 below. Plan detail results behind this summary tabulation are attached in Appendix D, Economic Impact for Each Alternative Resource Plan.

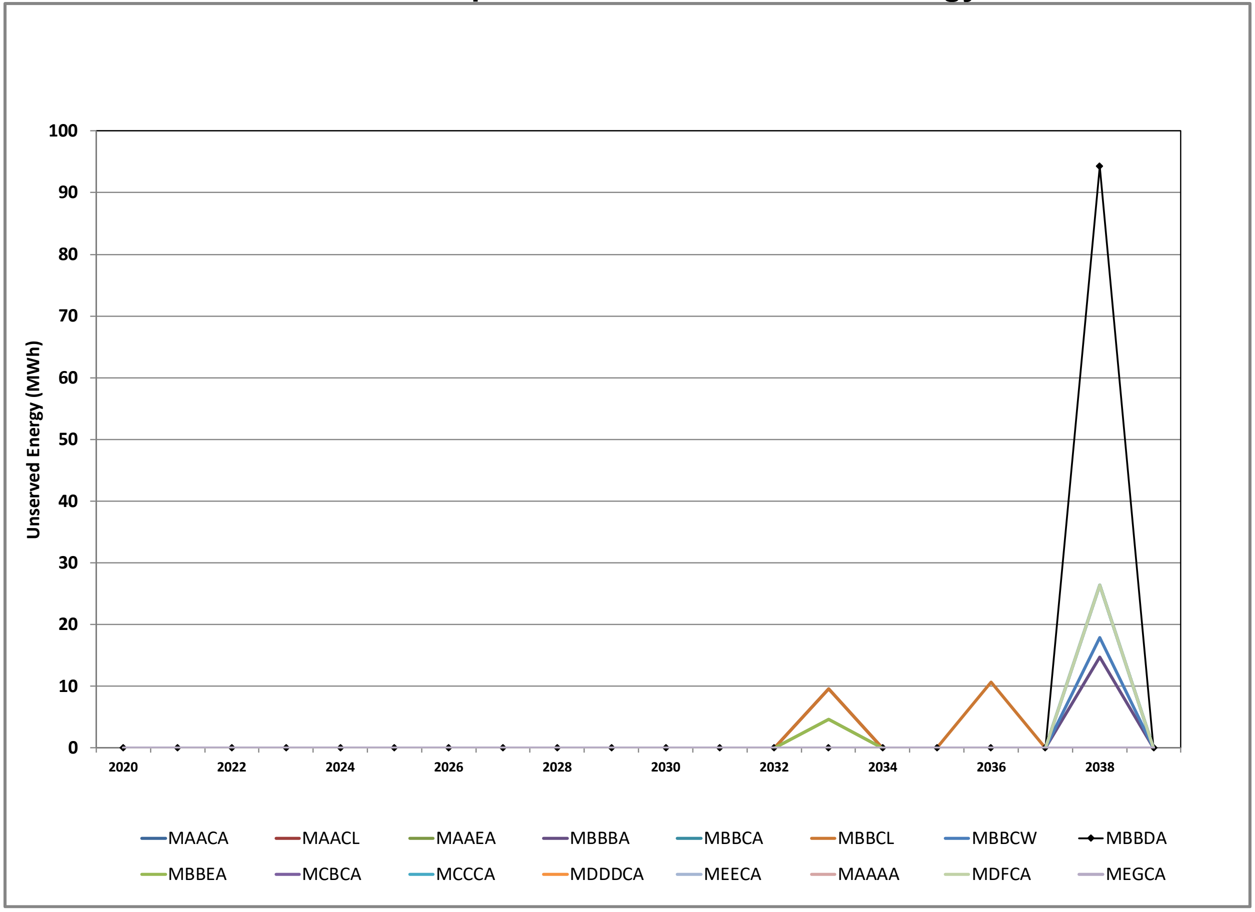
Table 20: Expected Value of Performance Measures ** Confidential**

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Annual Increase
MAACA	20,397	[redacted]	[redacted]
MCBCA	20,415	[redacted]	[redacted]
MBBCA	20,415	[redacted]	[redacted]
MBFCA	20,426	[redacted]	[redacted]
MEECA	20,430	[redacted]	[redacted]
MCCCA	20,443	[redacted]	[redacted]
MBBCW	20,444	[redacted]	[redacted]
MBBBA	20,446	[redacted]	[redacted]
MEGCA	20,454	[redacted]	[redacted]
MDDCA	20,466	[redacted]	[redacted]
MBBDA	20,479	[redacted]	[redacted]
MAAEA	20,530	[redacted]	[redacted]
MAAAA	20,571	[redacted]	[redacted]
MBBEA	20,584	[redacted]	[redacted]
MAACL	20,913	[redacted]	[redacted]
MBBCL	20,946	[redacted]	[redacted]

6.5 UNSERVED ENERGY

The expected value of unserved energy for all KCP&L Alternative Resource Plans is provided in Table 21 below:

Table 21: Expected Value of Unserved Energy



6.6 JOINT PLANNING EVERGY RESOURCE PLANS

Evergy Metro also considers it prudent resource planning to develop and analyze alternative resource plans that are based upon Evergy Metro, Evergy Missouri West, and Evergy Kansas Central combined. Evaluating alternative resource plans on a joint planning basis can provide a platform to determine if joint planning "serves the public interest" as mandated in 4 CSR 240-22.010 Policy Objectives.

Joint-planning Alternative Resource Plans were developed to reflect combinations of the individual-utility Alternative Resource Plans. For example, combined company plan ECCGA is the combination of Evergy Metro Alternative Resource Plan MCCCA (retire LaCygne 2 by 2029 and RAP- + DSR DSM) and Evergy Missouri West Alternative Resource Plan WAACD (retire Lake Road 4/6 by 2025 and RAP- + DSR DSM).

The NPVRR for each joint-planning alternative resource plan was determined under the same 18 scenarios analyzed for the stand-alone companies. For example, electricity market prices, natural gas prices, CO_2 allowance prices, etc. were unchanged from the stand-alone company scenarios.

The plan-naming convention utilized for the joint-planning Alternative Resource Plans developed is shown in Table 22. The Alternative Resource Plans were developed using various capacities of supply-side resources and demand-side resources. In total, twenty-eight joint-planning Alternative Resource Plans were developed for the 2020 Annual Update. An overview of the Alternative Resource Plans is shown in Table 23 through Table 26 below:

Table 22: Joint-Planning Alternative Resource Plan Naming Convention

E	A	A	G	A

UTILITY
E = EVERGY

RETIREMENT UNITS
A = LR 4/6
C = L-2, LR 4/6
D = L-1, LR 4/6
E = L-1, L-2, H-5, I-1, L-4, L-5, J-1, J-2, J-3, LR 4/6
F = LR 4/6, H-5, J-2, J-3
G = LR 4/6, J-1, J-2, J-3
H = LR 4/6, L-4, L-5, J-3
I = LR 4/6, L-4, L-5, L-1
J = LR 4/6, L-4
K = LR 4/6, L-4, L-5
M = LR 4/6, J-3
N = LR 4/6, L-4, J-3
P = LR 4/6, L-4, J-2, J-3
Q = LR 4/6, H-5
R = LR 4/6, L-4, J-1, J-2, J-3
S = LR 4/6, L-4, J-2, J-3, H-5
6 = LR 4/6, L-4, L-5, J-2, J-3, H-5
8 = LR 4/6, L-4, L-5, J-2, J-3

RETIREMENT DATES
A = Dec 31, 2024 (LR 4/6)
C = Dec 31, 2029 (L-2), Dec 31, 2024 (LR 4/6)
D = Dec 31, 2033 (L-1), Dec 31, 2024 (LR 4/6)
E = Dec 31, 2029 (H-5), Dec 31, 2034 (I-1), D, H, I
J = Dec 31, 2031 (L-4, L-5), Dec 31, 2032 (J-3), Dec 31, 2024 (LR 4/6)
K = Dec 31, 2024 (LR 4/6), Dec 31, 2031 (L-4, L-5), Dec 31, 2033 (L-1)
L = Dec 31, 2031 (L-4), Dec 31, 2024 (LR 4/6)
M = Dec 31, 2031 (L-4, L-5), Dec 31, 2024 (LR 4/6)
O = Dec 31, 2032 (J-3), Dec 31, 2024 (LR 4/6)
P = Dec 31, 2023 (H-5, or L-1, or L-2, J-3, or L-4 & L-5)
Q = Dec 31, 2024 (LR 4/6), Dec 31, 2033 (H-5), Dec 31, 2033 (J-2), Dec 31, 2023 (J-3)
R = Dec 31, 2024 (LR 4/6), Dec 31, 2034 (J-1), Dec 31, 2033 (J-2), Dec 31, 2023 (J-3)

DEMAND-SIDE MANAGEMENT
Option A = MAP
Option B = RAP
Option G = RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)
Option H = MEEIA Only

GENERATION ADDITIONS
A = CT
B = CC
S = Solar/CC or CT
W = Additional Wind

Definitions:

L-1: LaCygne-1	LR 4/6: Lake Road 4/6	RAP: Realistic Achievable Potential	CT - Combustion Turbine
L-2: LaCygne-2	I-1: Iatan-1	MAP: Maximum Achievable Potential	CC - Combined Cycle
H-5: Hawthorn-5	J-1: Jeffrey-1	RAP-: Realistic Achievable Potential Minus	
L-4: Lawrence-4	J-2: Jeffrey-2	DSR: Demand-Side Rates	
L-5: Lawrence-5	J-3: Jeffrey-3	MEEIA: Missouri Energy Efficiency Investment Act	

Table 23: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
E6PGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2023 Lawrence-5: Dec 31, 2023 Hawthorn-5: Dec 31, 2029 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	432 MW CT in 2030 216 MW CT in 2032 648 MW CT in 2033 648 MW CT in 2034 216 MW CT in 2035 432 MW CT in 2037
E8PGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2023 Lawrence-5: Dec 31, 2023 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	864 MW CT in 2033 648 MW CT in 2034 216 MW CT in 2036 216 MW CT in 2037
E8PGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2023 Lawrence-5: Dec 31, 2023 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2033 702 MW CC in 2034 702 MW CC in 2036
EAAGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2038
EAAGS	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 500 MW (2023) 23 MW (2028)	None
ECCGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 LaCygne-2: Dec 31, 2028	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2032 216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2038
ECPGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 LaCygne-2: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2032 216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2038
EDDGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 LaCygne-1: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	432 MW CT in 2034 216 MW CT in 2036 216 MW CT in 2037
EDPGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 LaCygne-1: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2024 216 MW CT in 2034 216 MW CT in 2036 216 MW CT in 2037

Table 24: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
EEEGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	LaCygne-1: Dec 31, 2033 LaCygne-2: Dec 31, 2028 Hawthorn-5: Dec 31, 2029 Iatan-1: Dec 31, 2034 Lawrence-4: Dec 31, 2031 Lawrence-5: Dec 31, 2031 Jeffrey-1: Dec 31, 2034 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2032 Lake Road 4/6: Dec 31, 2024	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	648 MW CT in 2030 648 MW CT in 2032 648 MW CT in 2033 1296 MW CT in 2034 1296 MW CT in 2035 432 MW CT in 2036 216 MW CT in 2037 216 MW CT in 2039
EEEGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	LaCygne-1: Dec 31, 2033 LaCygne-2: Dec 31, 2028 Hawthorn-5: Dec 31, 2029 Iatan-1: Dec 31, 2034 Lawrence-4: Dec 31, 2031 Lawrence-5: Dec 31, 2031 Jeffrey-1: Dec 31, 2034 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2032 Lake Road 4/6: Dec 31, 2024	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2030 702 MW CC in 2032 702 MW CC in 2033 1404 MW CC in 2034 1404 MW CC in 2035 702 MW CC in 2037
EFQGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023 Hawthorn-5: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2032 1296 MW CT in 2034 216 MW CT in 2036 216 MW CT in 2037 216 MW CT in 2038
EFQGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023 Hawthorn-5: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2033 702 MW CC in 2034 702 MW CC in 2036
EFQGS	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023 Hawthorn-5: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 500 MW (2023) 23 MW (2028)	1404 MW CC in 2034 702 MW CC in 2037
EGRGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-1: Dec 31, 2034 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2032 864 MW CT in 2034 648 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2037
EGRGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-1: Dec 31, 2034 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2033 702 MW CC in 2034 702 MW CC in 2035

Table 25: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
EGRGS	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-1: Dec 31, 2034 Jeffrey-2: Dec 31, 2033 Jeffrey-3: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 500 MW (2023) 23 MW (2028)	702 MW CC in 2034 702 MW CC in 2035 702 MW CC in 2036
EJLGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2031	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2037 216 MW CT in 2039
EKMGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2031 Lawrence-5: Dec 31, 2031	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2037
EKPGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2023 Lawrence-5: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2037
EMOGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-3: Dec 31, 2032	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2033 216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2037
EMPGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-3: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2032 216 MW CT in 2035 216 MW CT in 2036 216 MW CT in 2037
ENJGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2031 Jeffrey-3: Dec 31, 2032	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	432 MW CT in 2033 216 MW CT in 2036 216 MW CT in 2037 216 MW CT in 2039

Table 26: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
ENOGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2033 702 MW CC in 2034
EPOGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Lawrence-4: Dec 31, 2031 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	702 MW CC in 2033 702 MW CC in 2034 702 MW CC in 2038
EQAGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Hawthorn-5: Dec 31, 2029	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2033 216 MW CT in 2036 216 MW CT in 2037 216 MW CT in 2039
EQPGA	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Hawthorn-5: Dec 31, 2023	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	216 MW CT in 2033 216 MW CT in 2036 216 MW CT in 2037 216 MW CT in 2039
ESOGB	RAP- + DSR (K-MO)/RAP- + DSR (K-KS) + RAP- + DSR (GMO) + 1/2 RAP- (Westar)	Lake Road 4/6: Dec 31, 2024 Hawthorn-5: Dec 31, 2029 Lawrence-4: Dec 31, 2031 Jeffrey-3: Dec 31, 2032 Jeffrey-2: Dec 31, 2033	Wind: 805 MW (2021) Wind: 155 MW (2022)	Solar: 23 MW (2028)	1404 MW CC in 2033 702 MW CC in 2034

Revenue requirement results for each of the combined company Alternative Resource Plans are shown in Table 27 below:

Table 27: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank	PLAN	NPVRR ($MM)	DELTA
1	EAAGS	$65,333	$0
2	EAAGA	$65,423	$90
3	EJLGA	$65,453	$120
4	EKMGA	$65,478	$145
5	EMOGA	$65,484	$151
6	ENJGA	$65,494	$161
7	EMPGA	$65,533	$200
8	EQPGA	$65,538	$205
9	EQAGA	$65,560	$227
10	EDDGA	$65,566	$233
11	EKPGA	$65,584	$251
12	ENOGB	$65,587	$254
13	ECCGA	$65,605	$272
14	EGRGS	$65,612	$279
15	ECPGA	$65,625	$292
16	EPOGB	$65,626	$293
17	EFQGS	$65,640	$307
18	EDPGA	$65,662	$329
19	E8PGB	$65,735	$402
20	EFQGB	$65,750	$417
21	EGRGB	$65,750	$417
22	ESOGB	$65,758	$425
23	EGRGA	$65,760	$427
24	E8PGA	$65,767	$434
25	EFQGA	$65,773	$440
26	E6PGA	$65,992	$659
27	EEEGB	$66,558	$1,225
28	EEEGA	$66,883	$1,550

The joint-planning Alternative Resource Plan (ARP) EAAGS provided the lowest Net Present Value Revenue Requirement (NPVRR). This plan consists of retiring Lake Road 4/6 by 2025 and procuring 500 MW of solar generation. Demand-side programs are RAP-level for Evergy Missouri West and Evergy Metro as well as Demand-Side Rates for both utilities. Evergy Kansas Central included estimated DSM programs at a half-RAP level. Note that “RAP” refers to Realistic Achievable Potential.

Table 28 and Table 29 show the expected value of NPVRR for the joint plans with and without CO_2 restrictions. The “With” CO_2 restrictions shows the expected value over the nine scenarios that include the Company’s non-zero CO_2 emission allowance forecast. The “Without” CO_2 restrictions shows the expected value over the nine scenarios that have $0 CO_2 emission allowance cost. Under the scenarios with CO_2 restrictions, ARP EAAGS which includes retirement of Lake Road 4/6 by 2025 and procurement of 500 MW of solar generation is the lowest cost plan. Under scenarios without CO_2 restrictions, the same ARP, EAAGS, was the lowest cost plan as well. Given the results of the joint plans, no changes to the Evergy Metro or Evergy Missouri West Preferred Plans were warranted.

Table 28: Joint Plan Results With CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (CO2)							
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level	DSR
1	EAAGS	$66,508	$0	LR 4/6 12/24	500MW Solar 2023	RAP-	X
2	EAAGA	$66,632	$124	LR 4/6 12/24	216 MW CT 2038	RAP-	X
3	EGRGS	$66,635	$127	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	500 MW Solar 2023, 702 MW CC 2034, 2035. & 2036	RAP-	X
4	EJLGA	$66,657	$149	LR 4/6 12/24; LEC4 12/31	216 MW CT 2037 & 2039	RAP-	X
5	EKMGA	$66,663	$155	LR 4/6 12/24; LEC4 & LEC5 12/31	216 MW CT 2035, 2036 & 2037	RAP-	X
6	EMOGA	$66,663	$155	LR 4/6 12/24; J3 12/32	216 MW CT 2033, 2035, 2036 & 2037	RAP-	X
7	EFQGS	$66,666	$158	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	500 MW Solar 2023, 1404 MW CC 2034, 702 MW CC 2037	RAP-	X
8	ENJGA	$66,667	$159	LR 4/6 12/24; LEC4 12/31; J3 12/32	432 MW CT 2033; 216 MW CT 2036, 2037, & 2039	RAP-	X
9	EMPGA	$66,693	$185	LR 4/6 12/24; J3 12/23	216 MW CT 2032, 2035, 2036 & 2037	RAP-	X
10	ENOGB	$66,693	$185	LR 4/6 12/24; J3 12/32; J2 12/33	702 MW CC 2033 & 2034	RAP-	X
11	EQPGA	$66,713	$205	LR 4/6 12/24; H5 12/23	216 MW CT 2033, 2036, 2037 & 2039	RAP-	X
12	EPOGB	$66,720	$212	LR 4/6 12/24; LEC4 12/31; J3 12/32; J2 12/33	702 MW CC 2033, 2034 & 2038	RAP-	X
13	EQAGA	$66,740	$232	LR 4/6 12/24; H5 12/29	216 MW CT 2033, 2036, 2037 & 2039	RAP-	X
14	EDDGA	$66,750	$242	LR 4/6 12/24, LaC1 12/33	432 MW CT 2034; 216 MW CT 2036 & 2037	RAP-	X
15	EKPGA	$66,759	$251	LR 4/6 12/24; LEC4 & LEC5 12/23	216 MW CT 2035, 2036 & 2037	RAP-	X
16	ECCGA	$66,771	$263	LR 4/6 12/24; LaC2 12/28	216 MW CT 2032, 2035, 2036, & 2038	RAP-	X
17	ECPGA	$66,787	$279	LR 4/6 12/24; LaC2 12/23	216 MW CT 2032, 2035, 2036, & 2038	RAP-	X
18	E8PGB	$66,793	$285	LR 4/6 12/24; LEC4 & LEC5 12/23; J3 12/32; J2 12/33	702 MW CC 2033, 2034, & 2036	RAP-	X
19	EGRGB	$66,794	$286	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	702 MW CC 2033, 2034 & 2035	RAP-	X
20	EFQGB	$66,800	$292	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	702 MW CC 2033, 2034, & 2036	RAP-	X
21	ESOGB	$66,800	$292	LR 4/6 12/24; H5 12/29; LEC4 12/31; J3 12/32; J2 12/33	1404 MW CC 2033; 702 MW CC 2034	RAP-	X
22	EDPGA	$66,826	$318	LR 4/6 12/24, LaC1 12/23	216 MW CT 2024, 2034, 2036, & 2037	RAP-	X
23	EGRGA	$66,869	$361	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	216 MW CT 2032; 864 MW CT 2034; 648 MW CT 2035; 216 MW CT 2036 & 2037	RAP-	X
24	E8PGA	$66,884	$376	LR 4/6 12/24; LEC4 & LEC5 12/23; J3 12/32; J2 12/33	864 MW CT 2033; 648 MW CT 2034; 216 MW CT 2036 & 2037	RAP-	X
25	EFQGA	$66,887	$379	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	216 MW CT 2032, 1296 MW CT 2034, 216 MW CT 2036, 2037, & 2038	RAP-	X
26	E6PGA	$67,075	$567	LR 4/6 12/24; LEC4 & LEC5 12/23; H5 12/29; J3 12/32; J2 12/33	432 MW CT 2030; 216 MW CT 2032; 648 MW CT 2033; 648 MW CT 2034; 216 MW CT 2035; 432 MW CT 2037	RAP-	X
27	EEEGB	$67,358	$850	LR 4/6 12/24; LaC2 12/28; H5 12/29; LEC4 & LEC5 12/31; J3 12/32; LaC1 12/33; J2 12/33; I1 12/34; J1 12/34	702 MW CC 2030, 2032, & 2033; 1404 MW CC 2034 & 2035; 702 MW CC 2037	RAP-	X
28	EEEGA	$67,831	$1,323	LR 4/6 12/24, LaC2 12/28; H5 12/29; LEC4 & LEC5 12/31; J3 12/32; LaC1 12/33; J2 12/33; I1 12/34; J1 12/34	648 MW CT 2030, 2032, & 2033; 1296 MW CT 2034 & 2035; 432 MW CT 2036; 216 MW CT 2037 & 2039	RAP-	X

Table 29: Joint Plan Results Without CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (No CO2)							
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level	DSR
1	EAAGS	$63,571	$0	LR 4/6 12/24	500MW Solar 2023	RAP-	X
2	EAAGA	$63,609	$38	LR 4/6 12/24	216 MW CT 2038	RAP-	X
3	EJLGA	$63,648	$77	LR 4/6 12/24; LEC4 12/31	216 MW CT 2037 & 2039	RAP-	X
4	EKMGA	$63,700	$130	LR 4/6 12/24; LEC4 & LEC5 12/31	216 MW CT 2035, 2036 & 2037	RAP-	X
5	EMOGA	$63,714	$144	LR 4/6 12/24; J3 12/32	216 MW CT 2033, 2035, 2036 & 2037	RAP-	X
6	ENJGA	$63,734	$163	LR 4/6 12/24; LEC4 12/31; J3 12/32	432 MW CT 2033; 216 MW CT 2036, 2037, & 2039	RAP-	X
7	EQPGA	$63,776	$205	LR 4/6 12/24; H5 12/23	216 MW CT 2033, 2036, 2037 & 2039	RAP-	X
8	EDDGA	$63,790	$219	LR 4/6 12/24, LaC1 12/33	432 MW CT 2034; 216 MW CT 2036 & 2037	RAP-	X
9	EQAGA	$63,791	$220	LR 4/6 12/24; H5 12/29	216 MW CT 2033, 2036, 2037 & 2039	RAP-	X
10	EMPGA	$63,793	$223	LR 4/6 12/24; J3 12/23	216 MW CT 2032, 2035, 2036 & 2037	RAP-	X
11	EKPGA	$63,822	$251	LR 4/6 12/24; LEC4 & LEC5 12/23	216 MW CT 2035, 2036 & 2037	RAP-	X
12	ECCGA	$63,855	$284	LR 4/6 12/24; LaC2 12/28	216 MW CT 2032, 2035, 2036, & 2038	RAP-	X
13	ECPGA	$63,882	$311	LR 4/6 12/24; LaC2 12/23	216 MW CT 2032, 2035, 2036, & 2038	RAP-	X
14	EDPGA	$63,916	$346	LR 4/6 12/24, LaC1 12/23	216 MW CT 2024, 2034, 2036, & 2037	RAP-	X
15	ENOGB	$63,929	$358	LR 4/6 12/24; J3 12/32; J2 12/33	702 MW CC 2033 & 2034	RAP-	X
16	EPOGB	$63,986	$415	LR 4/6 12/24; LEC4 12/31; J3 12/32; J2 12/33	702 MW CC 2033, 2034 & 2038	RAP-	X
17	EGRGS	$64,078	$508	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	500 MW Solar 2023, 702 MW CC 2034, 2035. & 2036	RAP-	X
18	E8PGA	$64,092	$521	LR 4/6 12/24; LEC4 & LEC5 12/23; J3 12/32; J2 12/33	864 MW CT 2033; 648 MW CT 2034; 216 MW CT 2036 & 2037	RAP-	X
19	EGRGA	$64,098	$527	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	216 MW CT 2032; 864 MW CT 2034; 648 MW CT 2035; 216 MW CT 2036 & 2037	RAP-	X
20	EFQGS	$64,103	$532	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	500 MW Solar 2023, 1404 MW CC 2034, 702 MW CC 2037	RAP-	X
21	EFQGA	$64,103	$533	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	16 MW CT 2032, 1296 MW CT 2034, 216 MW CT 2036, 2037, & 203	RAP-	X
22	E8PGB	$64,148	$578	LR 4/6 12/24; LEC4 & LEC5 12/23; J3 12/32; J2 12/33	702 MW CC 2033, 2034, & 2036	RAP-	X
23	EFQGB	$64,174	$603	LR 4/6 12/24; J3 12/23; J2 12/33; H5 12/33	702 MW CC 2033, 2034, & 2036	RAP-	X
24	EGRGB	$64,183	$612	LR 4/6 12/24; J3 12/23; J2 12/33; J1 12/34	702 MW CC 2033, 2034 & 2035	RAP-	X
25	ESOGB	$64,194	$624	LR 4/6 12/24; H5 12/29; LEC4 12/31; J3 12/32; J2 12/33	1404 MW CC 2033; 702 MW CC 2034	RAP-	X
26	E6PGA	$64,369	$798	LR 4/6 12/24; LEC4 & LEC5 12/23; H5 12/29; J3 12/32; J2 12/33	432 MW CT 2030; 216 MW CT 2032; 648 MW CT 2033; 648 MW CT 2034; 216 MW CT 2035; 432 MW CT 2037	RAP-	X
27	EEEGB	$65,359	$1,788	LR 4/6 12/24; LaC2 12/28; H5 12/29; LEC4 & LEC5 12/31; J3 12/32; LaC1 12/33; J2 12/33; I1 12/34; J1 12/34	702 MW CC 2030, 2032, & 2033; 1404 MW CC 2034 & 2035; 702 MW CC 2037	RAP-	X
28	EEEGA	$65,461	$1,890	LR 4/6 12/24, LaC2 12/28; H5 12/29; LEC4 & LEC5 12/31; J3 12/32; LaC1 12/33; J2 12/33; I1 12/34; J1 12/34	648 MW CT 2030, 2032, & 2033; 1296 MW CT 2034 & 2035; 432 MW CT 2036; 216 MW CT 2037 & 2039	RAP-	X

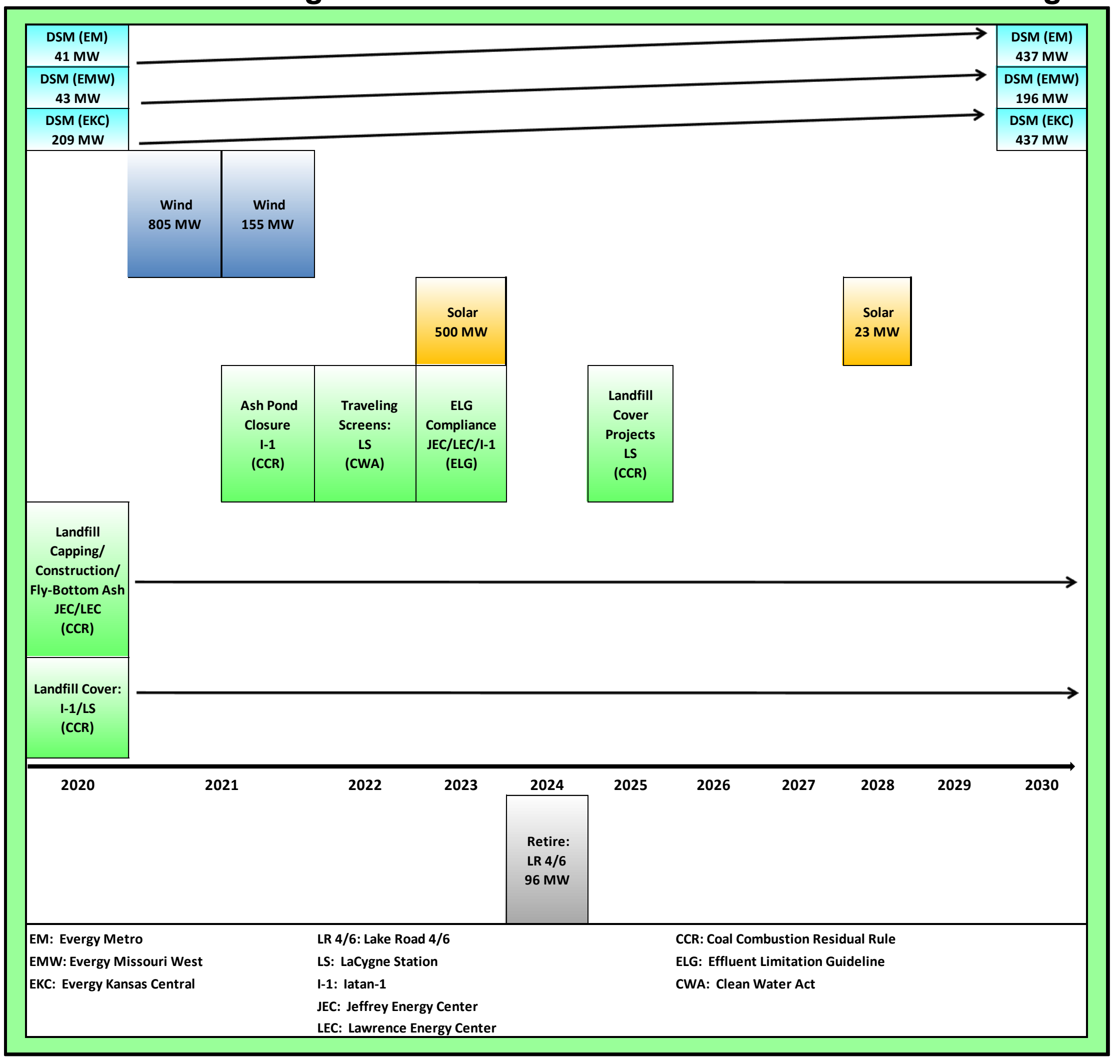
A summary tabulation of the expected value of all performance measures is provided in Table 30 below. Detailed results behind this summary tabulation are attached in Appendix D.

Table 30: Joint-Planning Expected Value of Performance Measures
**** Confidential****

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Annual Increase
EAAGS	$65,333	[redacted]	[redacted]
EAAGA	$65,423	[redacted]	[redacted]
EJLGA	$65,453	[redacted]	[redacted]
EKMGA	$65,478	[redacted]	[redacted]
EMOGA	$65,484	[redacted]	[redacted]
ENJGA	$65,494	[redacted]	[redacted]
EMPGA	$65,533	[redacted]	[redacted]
EQPGA	$65,538	[redacted]	[redacted]
EQAGA	$65,560	[redacted]	[redacted]
EDDGA	$65,566	[redacted]	[redacted]
EKPGA	$65,584	[redacted]	[redacted]
ENOGB	$65,587	[redacted]	[redacted]
ECCGA	$65,605	[redacted]	[redacted]
EGRGS	$65,612	[redacted]	[redacted]
ECPGA	$65,625	[redacted]	[redacted]
EPOGB	$65,626	[redacted]	[redacted]
EFQGS	$65,640	[redacted]	[redacted]
EDPGA	$65,662	[redacted]	[redacted]
E8PGB	$65,735	[redacted]	[redacted]
EFQGB	$65,750	[redacted]	[redacted]
EGRGB	$65,750	[redacted]	[redacted]
ESOGB	$65,758	[redacted]	[redacted]
EGRGA	$65,760	[redacted]	[redacted]
E8PGA	$65,767	[redacted]	[redacted]
EFQGA	$65,773	[redacted]	[redacted]
E6PGA	$65,992	[redacted]	[redacted]
EEEGB	$66,558	[redacted]	[redacted]
EEEGA	$66,883	[redacted]	[redacted]

The Joint-Planning Alternative Resource Plan that reflects the combination of the Evergy Metro Preferred Plan, MAACA and Evergy Missouri West Preferred Plan, WAACA as well as a ARP for Evergy Kansas Central is Alternative Resource Plan EAAGS. The joint-planning ARP is comprised of the following components for years 2020 – 2030 and shown in Figure 4 below:

Figure 4: Joint Planning Alternative Resource Plan EAAGS - 2020 through 2030



The Joint-Planning Alternative Resource Plan EAAGS for the 20-year planning period is shown in Table 31 below:

Table 31: Joint-Planning Alternative Resource Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)
2020	0			293	
2021	0	805		322	
2022	0	155		375	
2023	0		500	476	
2024	0			625	97
2025	0			717	
2026	0			812	
2027	0			896	
2028	0		23	967	
2029	0			1027	
2030	0			1070	
2031	0			1104	
2032	0			1127	
2033	0			1149	
2034	0			1167	
2035	0			1179	
2036	0			1194	
2037	0			1214	
2038	0			1266	
2039	0			1313	

6.7 JOINT-PLANNING ECONOMIC IMPACT

The economic impact by year of the Joint-Planning Alternative Resource Plan EAAGS is represented in Table 32 below. The economic impact of all plans can be found in Appendix D.

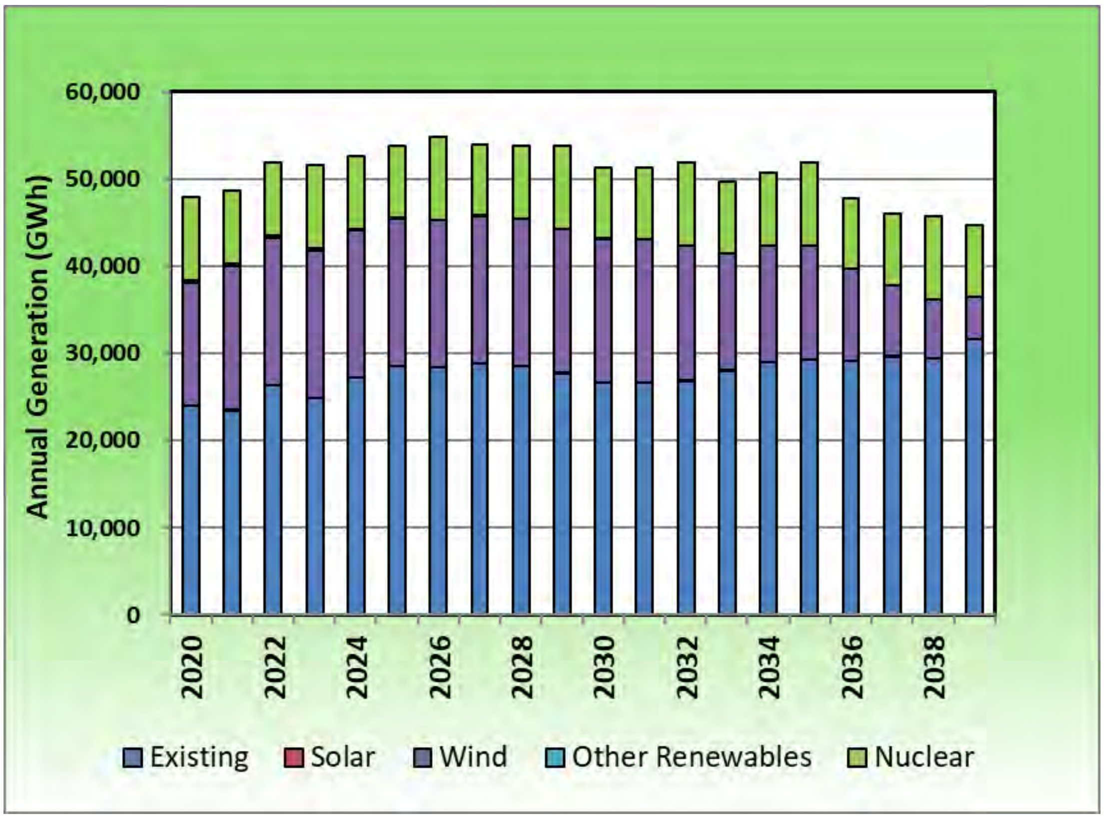
Table 32: Joint-Planning Alternative Resource Plan EAAGS - Economic Impact
**** Confidential****

Year	Revenue Requirements ($mm)	Levelized Annual Rates ($/kW-hr)	Rate Change % by Year
2020	5,369	[redacted]	[redacted]
2021	5,509	[redacted]	[redacted]
2022	5,627	[redacted]	[redacted]
2023	5,754	[redacted]	[redacted]
2024	5,887	[redacted]	[redacted]
2025	5,958	[redacted]	[redacted]
2026	6,035	[redacted]	[redacted]
2027	6,188	[redacted]	[redacted]
2028	6,321	[redacted]	[redacted]
2029	6,431	[redacted]	[redacted]
2030	6,687	[redacted]	[redacted]
2031	6,803	[redacted]	[redacted]
2032	6,917	[redacted]	[redacted]
2033	7,111	[redacted]	[redacted]
2034	7,305	[redacted]	[redacted]
2035	7,525	[redacted]	[redacted]
2036	7,946	[redacted]	[redacted]
2037	8,239	[redacted]	[redacted]
2038	8,434	[redacted]	[redacted]
2039	8,783	[redacted]	[redacted]

6.8 JOINT-PLANNING ANNUAL GENERATION

The expected value of annual generation of the Joint-Planning Alternative Resource Plan EAAGS is represented in Table 33 below. The annual generation of all Joint-Planning plans can be found in Appendix C, Generation and Emissions for Each Alternative Resource Plan.

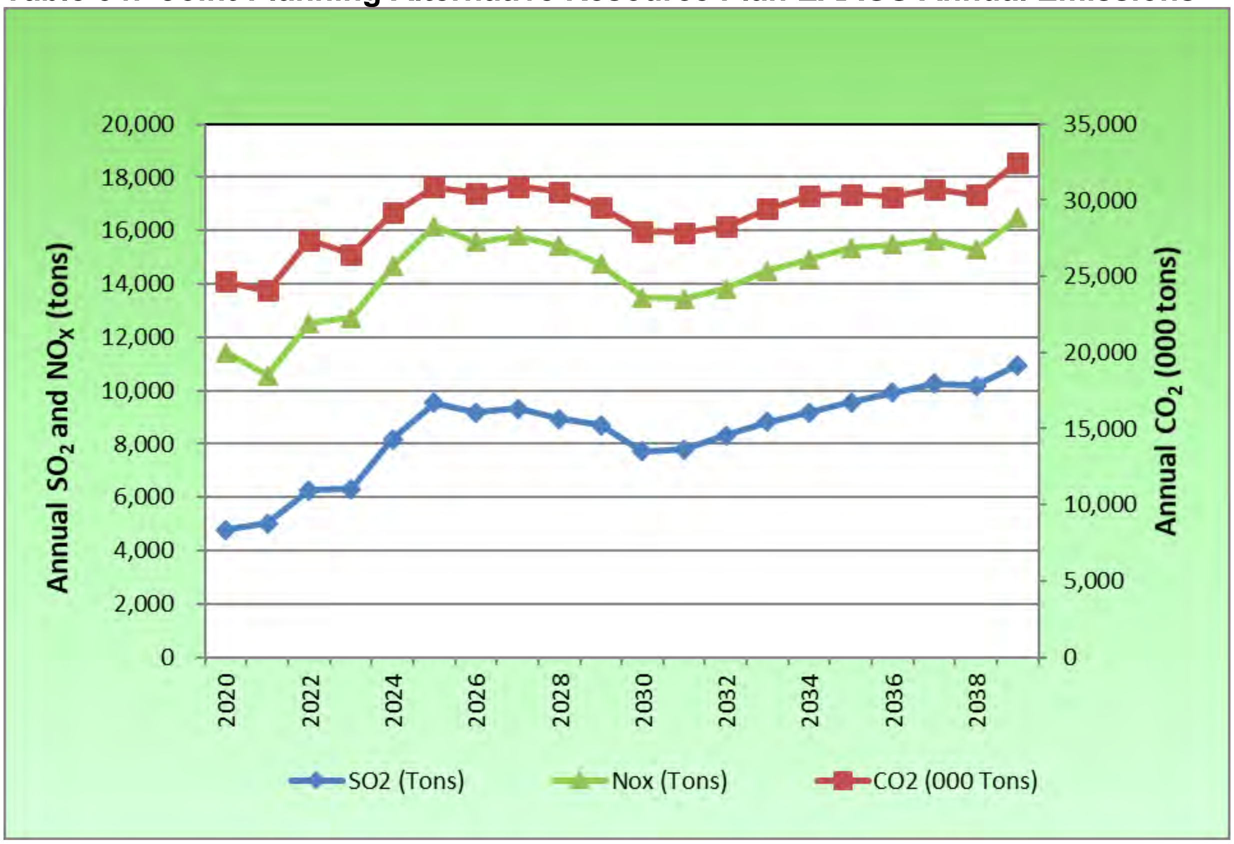
Table 33: Joint-Planning Alternative Resource Plan EAAGS Annual Generation



6.9 JOINT-PLANNING ANNUAL EMISSIONS

The expected values of annual emissions of the Joint-Planning Alternative Resource Plan EAAGS are represented in Table 34 below. The annual emissions of all Joint-Planning plans can be found in Appendix C.

Table 34: Joint-Planning Alternative Resource Plan EAAGS Annual Emissions



SECTION 7: RESOURCE ACQUISITION STRATEGY

7.1 2020 ANNUAL UPDATE PREFERRED PLAN

The Alternative Resource Plans (ARP) developed and analyzed under the requirements of 20 CSR 4240-22.060 were designed to meet the objectives of 20 CSR 4240-22.010(2). Demand-side resources - in conjunction with MEEIA - and growth of the renewables portfolio have been key components in the resource planning efforts of the company for over a decade.

The Company has selected MAACA as its Preferred Plan, which has the least cost Net Present Value of Revenue Requirement (NPVRR), in 12 of the 18 scenarios used to evaluate the performance of the 16 plans modeled for Evergy Metro.

The 2020 Annual Update Preferred Plan for the 20-year planning period is shown in Table 35 below:

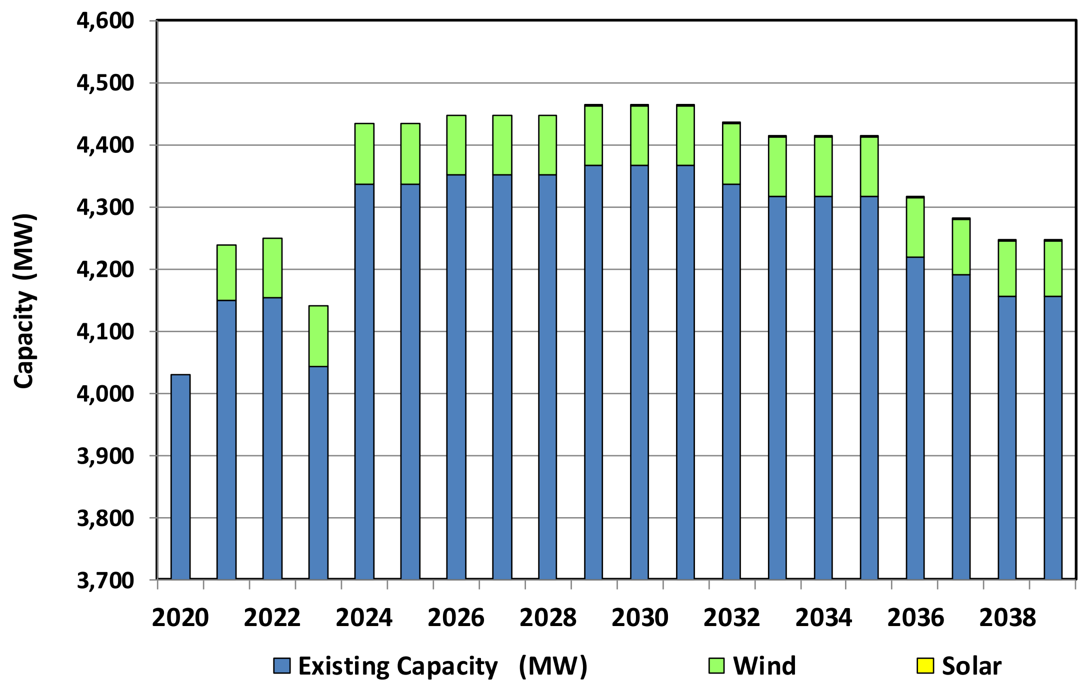
Table 35: 2020 Annual Update Preferred Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)
2020	0			41	
2021	0	377		57	
2022	0	30		79	
2023	0			121	
2024	0			184	
2025	0			226	
2026	0			276	
2027	0			328	
2028	0			373	
2029	0		13	411	
2030	0			437	
2031	0			457	
2032	0			472	
2033	0			489	
2034	0			504	
2035	0			512	
2036	0			517	
2037	0			524	
2038	0			549	
2039	0			575	

7.1.1 PREFERRED PLAN COMPOSITION

Existing and new capacity additions for the 2020 Annual Update Preferred Plan MAACA are shown in Table 36 below:

Table 36: Preferred Plan Capacity Additions



The Preferred Plan includes 150 MW of wind addition by 2022, and a 13 MW solar addition by 2028 to meet Missouri RPS requirements (if needed). The 150 MW wind addition is currently expected to be Evergy Metro's portion of the wind additions announced in January 2020. The DSM resources that were modeled consisted of a suite of eight residential and eight commercial programs three of which are demand response programs, two are educational programs, and eleven energy efficiency programs. The six DSR programs are: Time of Use, Time of Use with Electric Vehicle, Demand Rate, Demand Rate with Electric Vehicle, Real Time Pricing, and Inclining Block Rate.

7.1.2 PREFERRED PLAN ECONOMIC IMPACT

The expected value of economic impact by year of the Preferred Plan MAACA is represented in Table 37 below. The economic impact of all plans can be found in Appendix D.

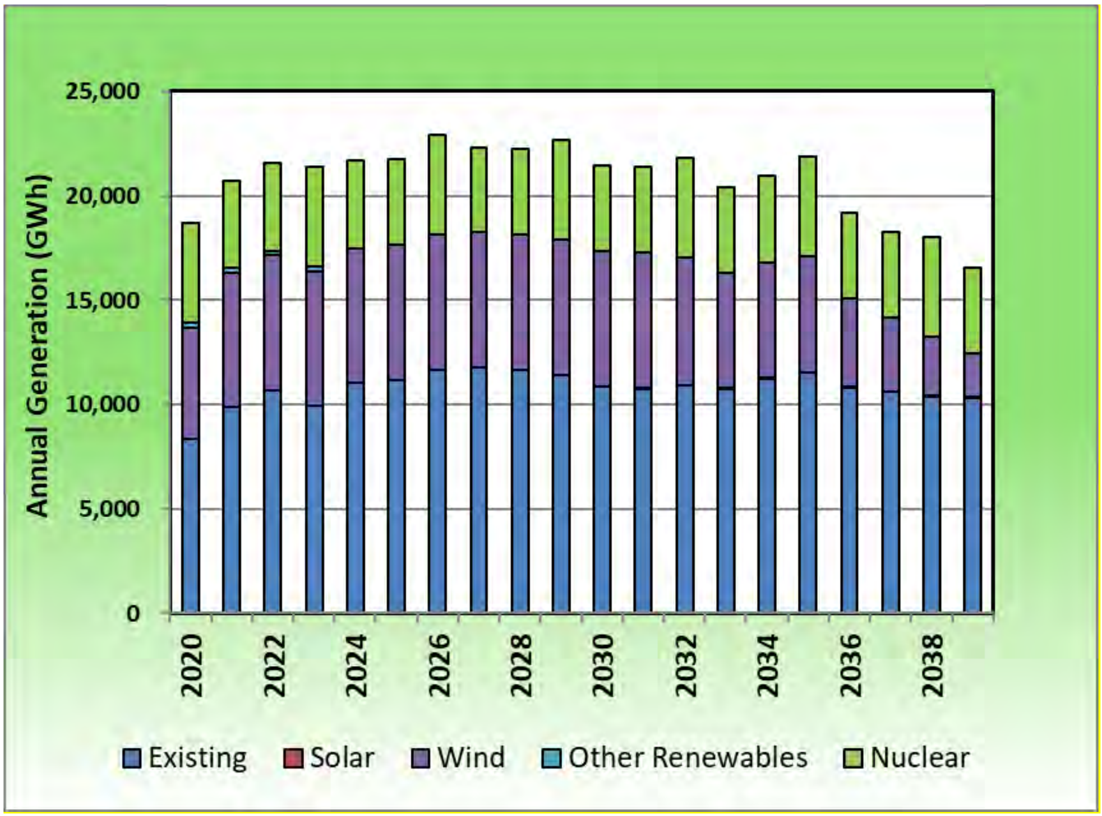
Table 37: Preferred Plan Economic Impact ** Confidential**

Year	NPVRR ($MM)	Levelized Annual Rates ($/kW-hr)	Rate Change % by Year
2020	1,835	[redacted]	[redacted]
2021	1,851	[redacted]	[redacted]
2022	1,856	[redacted]	[redacted]
2023	1,902	[redacted]	[redacted]
2024	1,934	[redacted]	[redacted]
2025	1,933	[redacted]	[redacted]
2026	1,917	[redacted]	[redacted]
2027	1,930	[redacted]	[redacted]
2028	1,952	[redacted]	[redacted]
2029	1,959	[redacted]	[redacted]
2030	2,017	[redacted]	[redacted]
2031	2,042	[redacted]	[redacted]
2032	2,061	[redacted]	[redacted]
2033	2,117	[redacted]	[redacted]
2034	2,141	[redacted]	[redacted]
2035	2,151	[redacted]	[redacted]
2036	2,266	[redacted]	[redacted]
2037	2,322	[redacted]	[redacted]
2038	2,366	[redacted]	[redacted]
2039	2,479	[redacted]	[redacted]

7.1.3 PREFERRED PLAN ANNUAL GENERATION

The expected value of annual generation for the Preferred Plan is shown in Table 38 below. The annual generation for all plans is included in Appendix C.

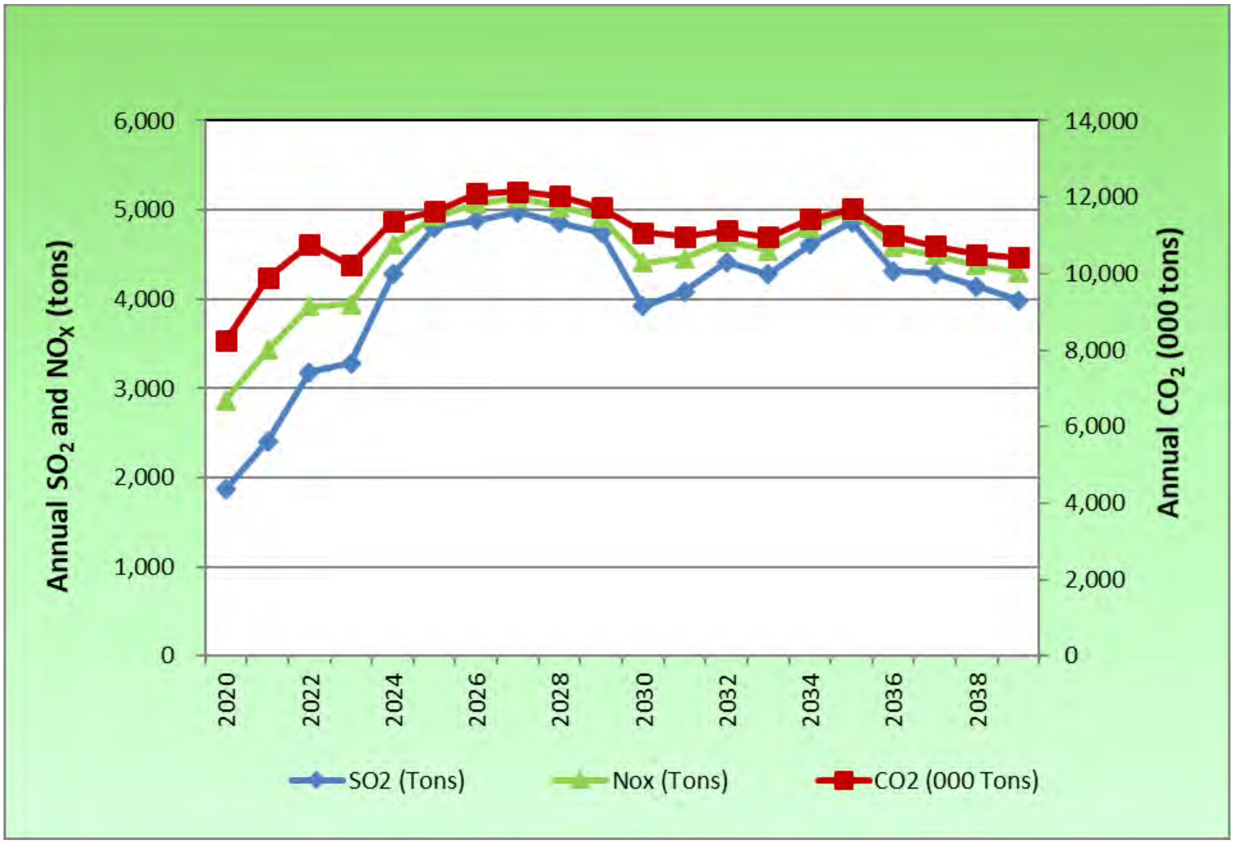
Table 38: Preferred Plan Annual Generation



7.1.4 PREFERRED PLAN ANNUAL EMISSIONS

The expected value of annual emissions for the Preferred Plan are shown in Table 39 below. The annual emissions for all plans are included in Appendix C.

Table 39: Preferred Plan Annual Emissions



7.1.5 NET PRESENT VALUE REVENUE REQUIREMENT COMPARISON

Table 40 below provides a comparison of the Net Present Value Revenue Requirement (NPVRR) and Rate Impacts between the Alternative Resource Plans for the 2020 Annual Update.

Table 40: 2020 Annual Update Preferred Plan NPVRR and Rate Impacts ** Confidential**

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Annual Increase
MAACA	20,397	[redacted]	[redacted]
MCBCA	20,415	[redacted]	[redacted]
MBBCA	20,415	[redacted]	[redacted]
MBFCA	20,426	[redacted]	[redacted]
MEECA	20,430	[redacted]	[redacted]
MCCCA	20,443	[redacted]	[redacted]
MBBCW	20,444	[redacted]	[redacted]
MBBBA	20,446	[redacted]	[redacted]
MEGCA	20,454	[redacted]	[redacted]
MDDCA	20,466	[redacted]	[redacted]
MBBDA	20,479	[redacted]	[redacted]
MAAEA	20,530	[redacted]	[redacted]
MAAAA	20,571	[redacted]	[redacted]
MBBEA	20,584	[redacted]	[redacted]
MAACL	20,913	[redacted]	[redacted]
MBBCL	20,946	[redacted]	[redacted]

C

7.2 CRITICAL UNCERTAIN FACTORS

The Critical Uncertain Factors for the 2020 Annual Update are identical to those in the 2018 Triennial IRP. The Company determined three risks to be critical uncertain factors that would be used in the risk sensitivities of the integrated analysis; load growth, natural gas prices and CO_2 credit prices. Consistent with the 2018 Triennial IRP, the probabilities for both load growth and natural gas are Mid 50% and High and Low states at 25% weighted probabilities. A change from the 2018 Triennial IRP regarding CO_2 restriction probabilities has been incorporated in the 2020 Annual Update. CO_2 restriction probabilities are modeled as a 60% probability there will be a CO_2 credit market and 40% probability that no CO_2 credit market will exist. The weighted endpoint probability is the product of these three weighted probabilities

The Critical Uncertain Factors identified were incorporated into a decision tree representation of the risks that will impact the performance of the alternative resource plans. A graphical representation of the decision tree risks is provided in Figure 5 below:

Figure 5: Critical Uncertain Factors With Decision Tree Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability	Least Cost Plan	Value ($MM)
1	High	High	Yes	3.8%	**MAACA**	**20,936**
2	High	High	No	2.5%	**MAACA**	**19,902**
3	High	Mid	Yes	7.5%	**MAACA**	**21,092**
4	High	Mid	No	5.0%	**MAACA**	**20,110**
5	High	Low	Yes	3.8%	**MEGCA**	**21,058**
6	High	Low	No	2.5%	**MEGCA**	**20,406**
7	Mid	High	Yes	7.5%	**MAACA**	**20,543**
8	Mid	High	No	5.0%	**MAACA**	**19,593**
9	Mid	Mid	Yes	15.0%	**MAACA**	**20,722**
10	Mid	Mid	No	10.0%	**MAACA**	**19,832**
11	Mid	Low	Yes	7.5%	**MEGCA**	**20,758**
12	Mid	Low	No	5.0%	**MEGCA**	**20,197**
13	Low	High	Yes	3.8%	**MAACA**	**20,239**
14	Low	High	No	2.5%	**MAACA**	**19,349**
15	Low	Mid	Yes	7.5%	**MAACA**	**20,437**
16	Low	Mid	No	5.0%	**MAACA**	**19,613**
17	Low	Low	Yes	3.8%	**MEGCA**	**20,555**
18	Low	Low	No	2.5%	**MEGCA**	**20,032**

Preferred Plan MAACA is the lowest cost on an expected value across all 18 endpoints, and in all but the 6 low gas individual scenarios, where MEGCA is the lowest cost. Plan MAACA has no additional plant retirements, while MEGCA would retire Hawthorn 5 by the end of 2024.

The following tables represent the sensitivities for the uncertain factors by scenario/endpoint for all 16 Plans.

7.2.1 CRITICAL UNCERTAIN FACTOR – HIGH LOAD GROWTH

HIGH LOAD GROWTH

HIGH GAS

With CO_2		MID CO_2		LOW CO_2	
Endpoint	1	Endpoint	1	Endpoint	2
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,936	MAACA	20935.9	MAACA	19,902
MBBCA	20,951	MBBCA	20951	MCBCA	19,968
MCBCA	20,951	MCBCA	20951.2	MBBCA	19,971
MBBCW	20,960	MBBCW	20959.6	MBBBA	20,004
MBBBA	20,972	MBBBA	20972	MBBCW	20,004
MCCCA	20,976	MCCCA	20976.5	MAAEA	20,027
MBFCA	20,977	MBFCA	20977.2	MCCCA	20,033
MEECA	20,986	MEECA	20986.1	MBBDA	20,035
MDDCA	20,997	MDDCA	20997.4	MBFCA	20,048
MBBDA	21,021	MBBDA	21020.9	MEECA	20,062
MEGCA	21,036	MEGCA	21035.7	MAAAA	20,080
MAAAA	21,085	MAAAA	21085.4	MDDCA	20,110
MAAEA	21,107	MAAEA	21107.5	MEGCA	20,129
MBBEA	21,159	MBBEA	21158.9	MBBEA	20,134
MAACL	21,542	MAACL	21542.3	MAACL	20,397
MBBCL	21,573	MBBCL	21573.2	MBBCL	20,481

MID GAS

HIGH CO_2		MID CO_2		LOW CO_2	
Endpoint	3	Endpoint	3	Endpoint	4
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	21,092	MAACA	21,092	MAACA	20,110
MBFCA	21,094	MBFCA	21,094	MBBCA	20,152
MBBCA	21,095	MBBCA	21,095	MCBCA	20,153
MCBCA	21,097	MCBCA	21,097	MBFCA	20,189
MEECA	21,103	MEECA	21,103	MBBBA	20,189
MBBCW	21,111	MBBCW	21,111	MBBCW	20,194
MCCCA	21,115	MCCCA	21,115	MCCCA	20,204
MBBBA	21,120	MBBBA	21,120	MBBDA	20,214
MDDCA	21,124	MDDCA	21,124	MEECA	20,218
MEGCA	21,128	MEGCA	21,128	MAAEA	20,218
MBBDA	21,164	MBBDA	21,164	MDDCA	20,254
MAAAA	21,250	MAAAA	21,250	MEGCA	20,259
MAAEA	21,250	MAAEA	21,250	MBBEA	20,298
MBBEA	21,291	MBBEA	21,291	MAAAA	20,299
MAACL	21,669	MAACL	21,669	MAACL	20,566
MBBCL	21,689	MBBCL	21,689	MBBCL	20,623

LOW GAS

HIGH CO_2		MID CO_2		LOW CO_2	
Endpoint	5	Endpoint	5	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MEGCA	21,058	MEGCA	21,058	MEGCA	20,406
MEECA	21,088	MEECA	21,088	MBFCA	20,410
MBFCA	21,143	MBFCA	21,143	MEECA	20,419
MBBCA	21,173	MBBCA	21,173	MBBCA	20,441
MCBCA	21,174	MCBCA	21,174	MCBCA	20,443
MDDCA	21,179	MDDCA	21,179	MAACA	20,447
MAACA	21,179	MAACA	21,179	MDDCA	20,450
MCCCA	21,181	MCCCA	21,181	MCCCA	20,451
MBBBA	21,207	MBBBA	21,207	MBBBA	20,489
MBBCW	21,209	MBBCW	21,209	MBBDA	20,495
MBBDA	21,236	MBBDA	21,236	MBBCW	20,502
MAAEA	21,300	MAAEA	21,300	MAAEA	20,517
MBBEA	21,330	MBBEA	21,330	MBBEA	20,546
MAAAA	21,362	MAAAA	21,362	MAAAA	20,661
MAACL	21,669	MAACL	21,669	MAACL	20,813
MBBCL	21,679	MBBCL	21,679	MBBCL	20,823

7.2.2 CRITICAL UNCERTAIN FACTOR – LOW LOAD GROWTH

LOW LOAD GROWTH

HIGH GAS	HIGH CO2		MID CO2		LOW CO2	
	Endpoint	13	Endpoint	13	Endpoint	14
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	MAACA	20,239	MAACA	20,239	MAACA	19,349
	MCBCA	20,253	MCBCA	20,253	MCBCA	19,415
	MBBCA	20,253	MBBCA	20,253	MBBCA	19,419
	MBBCW	20,262	MBBCW	20,262	MBBBA	19,450
	MBBBA	20,274	MBBBA	20,274	MBBCW	19,452
	MCCCA	20,280	MCCCA	20,280	MAAEA	19,473
	MBFCA	20,281	MBFCA	20,281	MCCCA	19,481
	MEECA	20,289	MEECA	20,289	MBBDA	19,482
	MDDCA	20,301	MDDCA	20,301	MBFCA	19,495
	MBBDA	20,325	MBBDA	20,325	MEECA	19,510
	MEGCA	20,339	MEGCA	20,339	MAAAA	19,525
	MAAAA	20,387	MAAAA	20,387	MDDCA	19,557
	MAAEA	20,413	MAAEA	20,413	MEGCA	19,578
	MBBEA	20,464	MBBEA	20,464	MBBEA	19,580
	MAACL	20,847	MAACL	20,847	MAACL	19,845
	MBBCL	20,877	MBBCL	20,877	MBBCL	19,930

MID GAS	HIGH CO2		MID CO2		LOW CO2	
	Endpoint	15	Endpoint	15	Endpoint	16
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	MAACA	20,437	MAACA	20,437	MAACA	19,613
	MBFCA	20,440	MBFCA	20,440	MBBCA	19,656
	MBBCA	20,441	MBBCA	20,441	MCBCA	19,656
	MCBCA	20,442	MCBCA	20,442	MBBBA	19,692
	MEECA	20,450	MEECA	20,450	MBFCA	19,692
	MBBCW	20,457	MBBCW	20,457	MBBCW	19,697
	MCCCA	20,460	MCCCA	20,460	MCCCA	19,708
	MBBBA	20,465	MBBBA	20,465	MBBDA	19,716
	MDDCA	20,471	MDDCA	20,471	MAAEA	19,720
	MEGCA	20,475	MEGCA	20,475	MEECA	19,721
	MBBDA	20,510	MBBDA	20,510	MDDCA	19,757
	MAAAA	20,594	MAAAA	20,594	MEGCA	19,762
	MAAEA	20,598	MAAEA	20,598	MBBEA	19,800
	MBBEA	20,638	MBBEA	20,638	MAAAA	19,800
	MAACL	21,017	MAACL	21,017	MAACL	20,070
	MBBCL	21,035	MBBCL	21,035	MBBCL	20,129

LOW GAS	HIGH CO2		MID CO2		LOW CO2	
	Endpoint	17	Endpoint	17	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	MEGCA	20,524	MEGCA	20,524	MEGCA	20,032
	MEECA	20,555	MEECA	20,555	MBFCA	20,035
	MBFCA	20,608	MBFCA	20,608	MEECA	20,045
	MBBCA	20,641	MBBCA	20,641	MBBCA	20,067
	MCBCA	20,641	MCBCA	20,641	MCBCA	20,068
	MAACA	20,647	MAACA	20,647	MAACA	20,072
	MDDCA	20,647	MDDCA	20,647	MDDCA	20,076
	MCCCA	20,648	MCCCA	20,648	MCCCA	20,076
	MBBBA	20,675	MBBBA	20,675	MBBBA	20,114
	MBBCW	20,677	MBBCW	20,677	MBBDA	20,120
	MBBDA	20,703	MBBDA	20,703	MBBCW	20,127
	MAAEA	20,769	MAAEA	20,769	MAAEA	20,143
	MBBEA	20,798	MBBEA	20,798	MBBEA	20,172
	MAAAA	20,829	MAAAA	20,829	MAAAA	20,287
	MAACL	21,137	MAACL	21,137	MAACL	20,440
	MBBCL	21,145	MBBCL	21,145	MBBCL	20,451

7.2.3 CRITICAL UNCERTAIN FACTOR – HIGH NATURAL GAS PRICES

HIGH NATURAL GAS

HIGH LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	1	Endpoint	1	Endpoint	2
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,936	MAACA	20935.9	MAACA	19,902
MBBCA	20,951	MBBCA	20951	MCBCA	19,968
MCBCA	20,951	MCBCA	20951.2	MBBCA	19,971
MBBCW	20,960	MBBCW	20959.6	MBBBA	20,004
MBBBA	20,972	MBBBA	20972	MBBCW	20,004
MCCCA	20,976	MCCCA	20976.5	MAAEA	20,027
MBFCA	20,977	MBFCA	20977.2	MCCCA	20,033
MEECA	20,986	MEECA	20986.1	MBBDA	20,035
MDDCA	20,997	MDDCA	20997.4	MBFCA	20,048
MBBDA	21,021	MBBDA	21020.9	MEECA	20,062
MEGCA	21,036	MEGCA	21035.7	MAAAA	20,080
MAAAA	21,085	MAAAA	21085.4	MDDCA	20,110
MAAEA	21,107	MAAEA	21107.5	MEGCA	20,129
MBBEA	21,159	MBBEA	21158.9	MBBEA	20,134
MAACL	21,542	MAACL	21542.3	MAACL	20,397
MBBCL	21,573	MBBCL	21573.2	MBBCL	20,481

MID LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	7	Endpoint	7	Endpoint	8
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,543	MAACA	20,543	MAACA	19,593
MCBCA	20,558	MCBCA	20,558	MCBCA	19,657
MBBCA	20,558	MBBCA	20,558	MBBCA	19,662
MBBCW	20,567	MBBCW	20,567	MBBBA	19,694
MBBBA	20,579	MBBBA	20,579	MBBCW	19,695
MCCCA	20,583	MCCCA	20,583	MAAEA	19,717
MBFCA	20,585	MBFCA	20,585	MCCCA	19,722
MEECA	20,594	MEECA	20,594	MBBDA	19,726
MDDCA	20,605	MDDCA	20,605	MBFCA	19,738
MBBDA	20,627	MBBDA	20,627	MEECA	19,753
MEGCA	20,643	MEGCA	20,643	MAAAA	19,770
MAAAA	20,692	MAAAA	20,692	MDDCA	19,800
MAAEA	20,715	MAAEA	20,715	MEGCA	19,821
MBBEA	20,766	MBBEA	20,766	MBBEA	19,824
MAACL	21,151	MAACL	21,151	MAACL	20,087
MBBCL	21,181	MBBCL	21,181	MBBCL	20,170

LOW LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	13	Endpoint	13	Endpoint	14
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,239	MAACA	20,239	MAACA	19,349
MCBCA	20,253	MCBCA	20,253	MCBCA	19,415
MBBCA	20,253	MBBCA	20,253	MBBCA	19,419
MBBCW	20,262	MBBCW	20,262	MBBBA	19,450
MBBBA	20,274	MBBBA	20,274	MBBCW	19,452
MCCCA	20,280	MCCCA	20,280	MAAEA	19,473
MBFCA	20,281	MBFCA	20,281	MCCCA	19,481
MEECA	20,289	MEECA	20,289	MBBDA	19,482
MDDCA	20,301	MDDCA	20,301	MBFCA	19,495
MBBDA	20,325	MBBDA	20,325	MEECA	19,510
MEGCA	20,339	MEGCA	20,339	MAAAA	19,525
MAAAA	20,387	MAAAA	20,387	MDDCA	19,557
MAAEA	20,413	MAAEA	20,413	MEGCA	19,578
MBBEA	20,464	MBBEA	20,464	MBBEA	19,580
MAACL	20,847	MAACL	20,847	MAACL	19,845
MBBCL	20,877	MBBCL	20,877	MBBCL	19,930

7.2.4 CRITICAL UNCERTAIN FACTOR – LOW NATURAL GAS PRICES

LOW NATURAL GAS

HIGH LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	5	Endpoint	5	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MEGCA	21,058	MEGCA	21,058	MEGCA	20,406
MEECA	21,088	MEECA	21,088	MBFCA	20,410
MBFCA	21,143	MBFCA	21,143	MEECA	20,419
MBBCA	21,173	MBBCA	21,173	MBBCA	20,441
MCBCA	21,174	MCBCA	21,174	MCBCA	20,443
MDDCA	21,179	MDDCA	21,179	MAACA	20,447
MAACA	21,179	MAACA	21,179	MDDCA	20,450
MCCCA	21,181	MCCCA	21,181	MCCCA	20,451
MBBBA	21,207	MBBBA	21,207	MBBBA	20,489
MBBCW	21,209	MBBCW	21,209	MBBDA	20,495
MBBDA	21,236	MBBDA	21,236	MBBCW	20,502
MAAEA	21,300	MAAEA	21,300	MAAEA	20,517
MBBEA	21,330	MBBEA	21,330	MBBEA	20,546
MAAAA	21,362	MAAAA	21,362	MAAAA	20,661
MAACL	21,669	MAACL	21,669	MAACL	20,813
MBBCL	21,679	MBBCL	21,679	MBBCL	20,823

MID LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	11	Endpoint	11	Endpoint	12
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MEGCA	20,758	MEGCA	20,758	MEGCA	20,197
MEECA	20,789	MEECA	20,789	MBFCA	20,201
MBFCA	20,842	MBFCA	20,842	MEECA	20,210
MBBCA	20,873	MBBCA	20,873	MBBCA	20,233
MCBCA	20,873	MCBCA	20,873	MCBCA	20,233
MAACA	20,879	MAACA	20,879	MAACA	20,237
MDDCA	20,879	MDDCA	20,879	MCCCA	20,242
MCCCA	20,881	MCCCA	20,881	MDDCA	20,242
MBBBA	20,908	MBBBA	20,908	MBBBA	20,280
MBBCW	20,909	MBBCW	20,909	MBBDA	20,286
MBBDA	20,935	MBBDA	20,935	MBBCW	20,293
MAAEA	21,002	MAAEA	21,002	MAAEA	20,308
MBBEA	21,031	MBBEA	21,031	MBBEA	20,338
MAAAA	21,061	MAAAA	21,061	MAAAA	20,452
MAACL	21,370	MAACL	21,370	MAACL	20,605
MBBCL	21,379	MBBCL	21,379	MBBCL	20,615

LOW LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	17	Endpoint	17	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MEGCA	20,524	MEGCA	20,524	MEGCA	20,032
MEECA	20,555	MEECA	20,555	MBFCA	20,035
MBFCA	20,608	MBFCA	20,608	MEECA	20,045
MBBCA	20,641	MBBCA	20,641	MBBCA	20,067
MCBCA	20,641	MCBCA	20,641	MCBCA	20,068
MAACA	20,647	MAACA	20,647	MAACA	20,072
MDDCA	20,647	MDDCA	20,647	MDDCA	20,076
MCCCA	20,648	MCCCA	20,648	MCCCA	20,076
MBBBA	20,675	MBBBA	20,675	MBBBA	20,114
MBBCW	20,677	MBBCW	20,677	MBBDA	20,120
MBBDA	20,703	MBBDA	20,703	MBBCW	20,127
MAAEA	20,769	MAAEA	20,769	MAAEA	20,143
MBBEA	20,798	MBBEA	20,798	MBBEA	20,172
MAAAA	20,829	MAAAA	20,829	MAAAA	20,287
MAACL	21,137	MAACL	21,137	MAACL	20,440
MBBCL	21,145	MBBCL	21,145	MBBCL	20,451

7.2.5 CRITICAL UNCERTAIN FACTOR – CO_2 RESTRICTIONS

CO_2 RESTRICTIONS

HIGH LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	1	Endpoint	3	Endpoint	5
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,936	MAACA	21,092	MEGCA	21,058
MBBCA	20,951	MBFCA	21,094	MEECA	21,088
MCBCA	20,951	MBBCA	21,095	MBFCA	21,143
MBBCW	20,960	MCBCA	21,097	MBBCA	21,173
MBBBA	20,972	MEECA	21,103	MCBCA	21,174
MCCCA	20,976	MBBCW	21,111	MDDCA	21,179
MBFCA	20,977	MCCCA	21,115	MAACA	21,179
MEECA	20,986	MBBBA	21,120	MCCCA	21,181
MDDCA	20,997	MDDCA	21,124	MBBBA	21,207
MBBDA	21,021	MEGCA	21,128	MBBCW	21,209
MEGCA	21,036	MBBDA	21,164	MBBDA	21,236
MAAAA	21,085	MAAAA	21,250	MAAEA	21,300
MAAEA	21,107	MAAEA	21,250	MBBEA	21,330
MBBEA	21,159	MBBEA	21,291	MAAAA	21,362
MAACL	21,542	MAACL	21,669	MAACL	21,669
MBBCL	21,573	MBBCL	21,689	MBBCL	21,679

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	7	Endpoint	9	Endpoint	11
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,543	MAACA	20,722	MEGCA	20,758
MCBCA	20,558	MBFCA	20,726	MEECA	20,789
MBBCA	20,558	MBBCA	20,727	MBFCA	20,842
MBBCW	20,567	MCBCA	20,727	MBBCA	20,873
MBBBA	20,579	MEECA	20,736	MCBCA	20,873
MCCCA	20,583	MBBCW	20,743	MAACA	20,879
MBFCA	20,585	MCCCA	20,745	MDDCA	20,879
MEECA	20,594	MBBBA	20,751	MCCCA	20,881
MDDCA	20,605	MDDCA	20,755	MBBBA	20,908
MBBDA	20,627	MEGCA	20,760	MBBCW	20,909
MEGCA	20,643	MBBDA	20,794	MBBDA	20,935
MAAAA	20,692	MAAAA	20,880	MAAEA	21,002
MAAEA	20,715	MAAEA	20,882	MBBEA	21,031
MBBEA	20,766	MBBEA	20,923	MAAAA	21,061
MAACL	21,151	MAACL	21,302	MAACL	21,370
MBBCL	21,181	MBBCL	21,321	MBBCL	21,379

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	13	Endpoint	15	Endpoint	17
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	20,239	MAACA	20,437	MEGCA	20,524
MCBCA	20,253	MBFCA	20,440	MEECA	20,555
MBBCA	20,253	MBBCA	20,441	MBFCA	20,608
MBBCW	20,262	MCBCA	20,442	MBBCA	20,641
MBBBA	20,274	MEECA	20,450	MCBCA	20,641
MCCCA	20,280	MBBCW	20,457	MAACA	20,647
MBFCA	20,281	MCCCA	20,460	MDDCA	20,647
MEECA	20,289	MBBBA	20,465	MCCCA	20,648
MDDCA	20,301	MDDCA	20,471	MBBBA	20,675
MBBDA	20,325	MEGCA	20,475	MBBCW	20,677
MEGCA	20,339	MBBDA	20,510	MBBDA	20,703
MAAAA	20,387	MAAAA	20,594	MAAEA	20,769
MAAEA	20,413	MAAEA	20,598	MBBEA	20,798
MBBEA	20,464	MBBEA	20,638	MAAAA	20,829
MAACL	20,847	MAACL	21,017	MAACL	21,137
MBBCL	20,877	MBBCL	21,035	MBBCL	21,145

7.2.6 CRITICAL UNCERTAIN FACTOR – CO_2 – NO RESTRICTIONS

NO CO_2 RESTRICTIONS

HIGH LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	2	Endpoint	4	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	19,902	MAACA	20109.6	MEGCA	20,406
MCBCA	19,968	MBBCA	20152.3	MBFCA	20,410
MBBCA	19,971	MCBCA	20153	MEECA	20,419
MBBBA	20,004	MBFCA	20189.1	MBBCA	20,441
MBBCW	20,004	MBBBA	20189.3	MCBCA	20,443
MAAEA	20,027	MBBCW	20193.8	MAACA	20,447
MCCCA	20,033	MCCCA	20204.1	MDDCA	20,450
MBBDA	20,035	MBBDA	20213.7	MCCCA	20,451
MBFCA	20,048	MEECA	20217.5	MBBBA	20,489
MEECA	20,062	MAAEA	20217.6	MBBDA	20,495
MAAAA	20,080	MDDCA	20253.7	MBBCW	20,502
MDDCA	20,110	MEGCA	20258.6	MAAEA	20,517
MEGCA	20,129	MBBEA	20298.1	MBBEA	20,546
MBBEA	20,134	MAAAA	20298.8	MAAAA	20,661
MAACL	20,397	MAACL	20565.6	MAACL	20,813
MBBCL	20,481	MBBCL	20623.4	MBBCL	20,823

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	8	Endpoint	10	Endpoint	12
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	19,593	MAACA	19,832	MEGCA	20,197
MCBCA	19,657	MCBCA	19,875	MBFCA	20,201
MBBCA	19,662	MBBCA	19,875	MEECA	20,210
MBBBA	19,694	MBFCA	19,911	MBBCA	20,233
MBBCW	19,695	MBBBA	19,911	MCBCA	20,233
MAAEA	19,717	MBBCW	19,916	MAACA	20,237
MCCCA	19,722	MCCCA	19,926	MCCCA	20,242
MBBDA	19,726	MBBDA	19,935	MDDCA	20,242
MBFCA	19,738	MAAEA	19,939	MBBBA	20,280
MEECA	19,753	MEECA	19,940	MBBDA	20,286
MAAAA	19,770	MDDCA	19,976	MBBCW	20,293
MDDCA	19,800	MEGCA	19,981	MAAEA	20,308
MEGCA	19,821	MBBEA	20,019	MBBEA	20,338
MBBEA	19,824	MAAAA	20,021	MAAAA	20,452
MAACL	20,087	MAACL	20,287	MAACL	20,605
MBBCL	20,170	MBBCL	20,345	MBBCL	20,615

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	14	Endpoint	16	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
MAACA	19,349	MAACA	19,613	MEGCA	20,032
MCBCA	19,415	MBBCA	19,656	MBFCA	20,035
MBBCA	19,419	MCBCA	19,656	MEECA	20,045
MBBBA	19,450	MBBBA	19,692	MBBCA	20,067
MBBCW	19,452	MBFCA	19,692	MCBCA	20,068
MAAEA	19,473	MBBCW	19,697	MAACA	20,072
MCCCA	19,481	MCCCA	19,708	MDDCA	20,076
MBBDA	19,482	MBBDA	19,716	MCCCA	20,076
MBFCA	19,495	MAAEA	19,720	MBBBA	20,114
MEECA	19,510	MEECA	19,721	MBBDA	20,120
MAAAA	19,525	MDDCA	19,757	MBBCW	20,127
MDDCA	19,557	MEGCA	19,762	MAAEA	20,143
MEGCA	19,578	MBBEA	19,800	MBBEA	20,172
MBBEA	19,580	MAAAA	19,800	MAAAA	20,287
MAACL	19,845	MAACL	20,070	MAACL	20,440
MBBCL	19,930	MBBCL	20,129	MBBCL	20,451

7.2.7 CRITICAL UNCERTAIN FACTORS – SUMMARY AND EVALUATION

This summary table, Table 41 provides the expected value for NPVRR across the eighteen endpoint tree by plan and the value for NPVRR for the mid-load, mid-gas and CO_2 – Yes scenario, Endpoint 9.

Table 41: Alternative Resource Plan NPVRRs

Expected Value			Endpoint 9		
PLAN	NPVRR ($MM)	DELTA	PLAN	NPVRR ($MM)	DELTA
MAACA	$20,397.30	$0.00	MAACA	$20,722.34	$0.00
MCBCA	$20,414.87	$17.57	MBFCA	$20,725.85	$3.52
MBBCA	$20,414.90	$17.59	MBBCA	$20,726.72	$4.38
MBFCA	$20,425.61	$28.31	MCBCA	$20,727.26	$4.92
MEECA	$20,429.95	$32.64	MEECA	$20,735.62	$13.29
MCCCA	$20,442.80	$45.49	MBBCW	$20,742.60	$20.27
MBBCW	$20,443.98	$46.67	MCCCA	$20,745.28	$22.94
MBBBA	$20,445.60	$48.30	MBBBA	$20,750.91	$28.57
MEGCA	$20,453.99	$56.68	MDDCA	$20,755.05	$32.71
MDDCA	$20,466.33	$69.03	MEGCA	$20,760.27	$37.93
MBBDA	$20,478.84	$81.54	MBBDA	$20,794.19	$71.85
MAAEA	$20,530.27	$132.96	MAAAA	$20,879.71	$157.37
MAAAA	$20,571.06	$173.76	MAAEA	$20,881.86	$159.52
MBBEA	$20,584.21	$186.90	MBBEA	$20,922.75	$200.41
MAACL	$20,913.06	$515.75	MAACL	$21,301.75	$579.42
MBBCL	$20,945.69	$548.38	MBBCL	$21,320.64	$598.31

7.3 IMPLEMENTATION PLAN

The Implementation Plan provided in the 2018 KCP&L Triennial IRP is materially changing due to the wind additions announced in the December 2019 Preferred Resource Plan filing. Additionally, Evergy will issue an all-source Request for Proposal in the coming months to further refine the solar assumptions used in identifying the potential for adding 500 MW of solar generation in the joint-planning Alternative Resource Plan EAAGS. The 2021 IRP will utilize the results from the RFP to further evaluate solar generation.

It should also be noted that Evergy implemented a Distributed Energy Resource Management System (DERMS) in 2019 as a MEEIA pilot project. The DERMS system is currently being used to centrally manage the Company's Demand Response (DR) programs, but it has the capability to manage all forms of customer and Company distributed energy resource (DER) in the future.

The Demand-Side Management program schedule has been updated and the current schedules for ongoing and future DSM programs are provided in Table 48 and Table 49 below.

7.3.1 SUPPLY-SIDE IMPLEMENTATION SCHEDULES

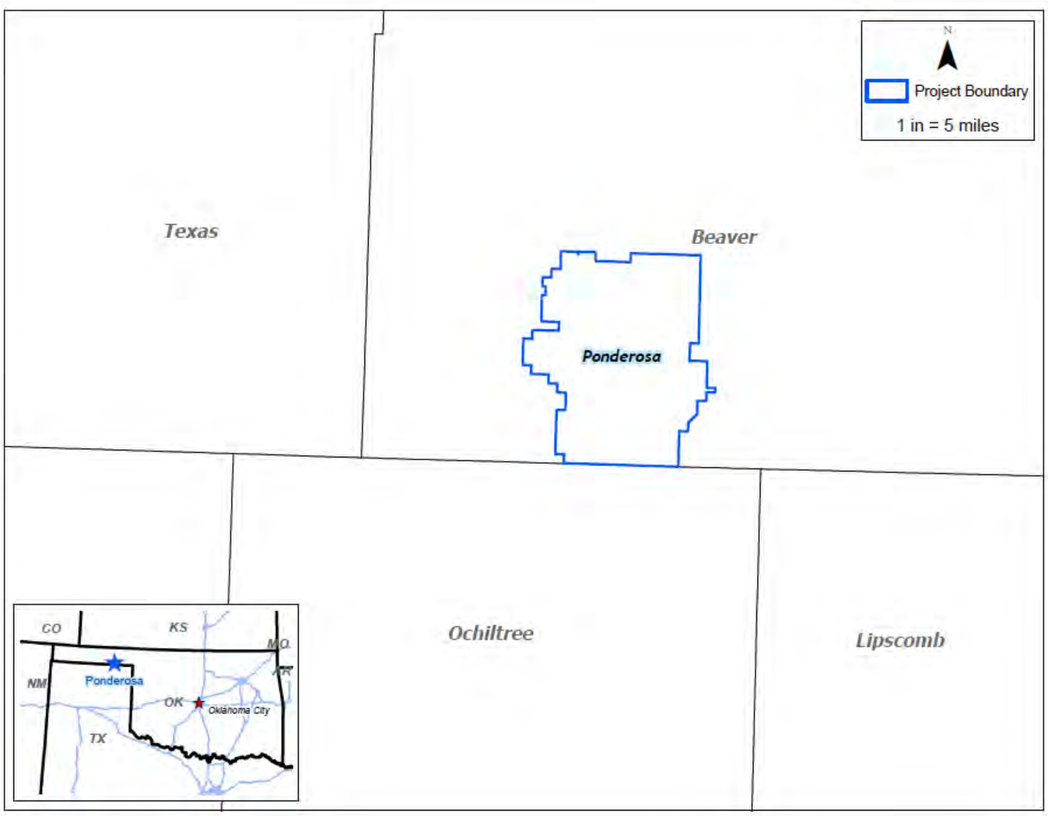
In the December 2019 Preferred Resource Plan filing statements were made that Evergy had issued a Request for Proposals ("RFP") on November 16, 2018 to obtain and evaluate wind project offers from wind developers. The RFP responses and customer interest were such that Evergy Metro and Evergy Missouri West opted to pursue three new wind facilities totaling ~532 MWs of nameplate capacity, 407 MWs of which is currently projected to be allocated to Evergy Metro. The final allocation to Evergy Metro will be determined at a later date. The three wind facilities were obtained through Power Purchase Agreements ("PPA") with two being located in Kansas and one located in Oklahoma. The PPAs were executed in September and October 2019 and have expected Commercial Operating Dates ("COD") of 2020 or 2021.

As described above, 532 MW of wind additions are from three power purchase agreements (PPA) executed in 2019. Ponderosa Wind is a 200 MW wind energy development with Evergy being an off-taker of 178 MW of the facility. The facility is currently planned to be in-service 4Q, 2020. Ponderosa Wind is cited over approximately 35,000 acres in Beaver County, Oklahoma and owned by NextEra. Table 42 and Table 43 provide current major milestones and location of the Ponderosa Wind project.

Table 42: Ponderosa Wind Milestone Activities

Milestone Description	Milestone Dates
Start of Construction	March, 2020
Turbine Deliveries and Erection Begin	May, 2020
Interconnect Facilities Complete	November, 2020
Facility Start-Up Testing	November, 2020
Commercial Operation Date	December, 2020

Table 43: Ponderosa Wind Location

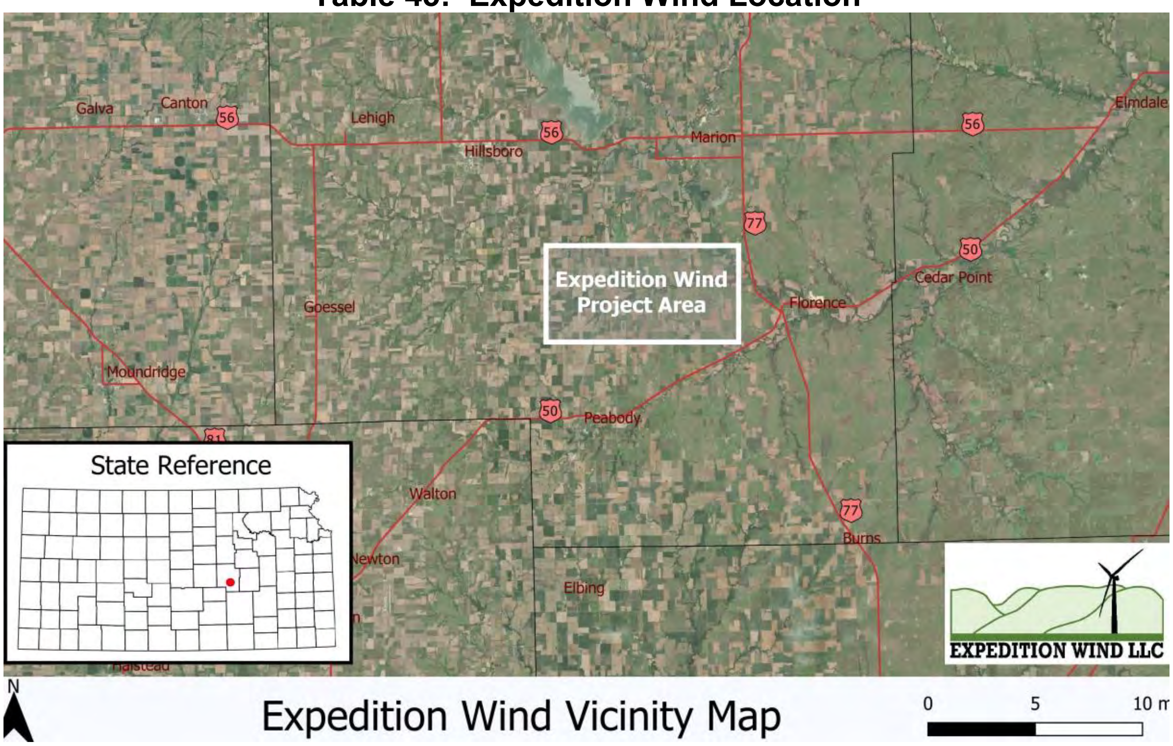


Expedition Wind is a 199 MW wind energy development with Evergy being the energy off-taker of the entire facility. The facility is currently planned to be in-service 3Q, 2021. Expedition Wind is cited over approximately 22,000 acres in Marion County, Kansas and owned by National Renewables Solutions and Ares Management Corporation. Table 44 and Table 45 provide current major milestones and the location of the Expedition Wind project.

Table 44: Expedition Wind Milestone Activities

Milestone Description	Milestone Dates
Start of Construction	?, 2021
Turbine Deliveries and Erection Begin	?, 2021
Interconnect Facilities Complete	?, 2021
Facility Start-Up Testing	?, 2021
Commercial Operation Date	July, 2021

Table 45: Expedition Wind Location

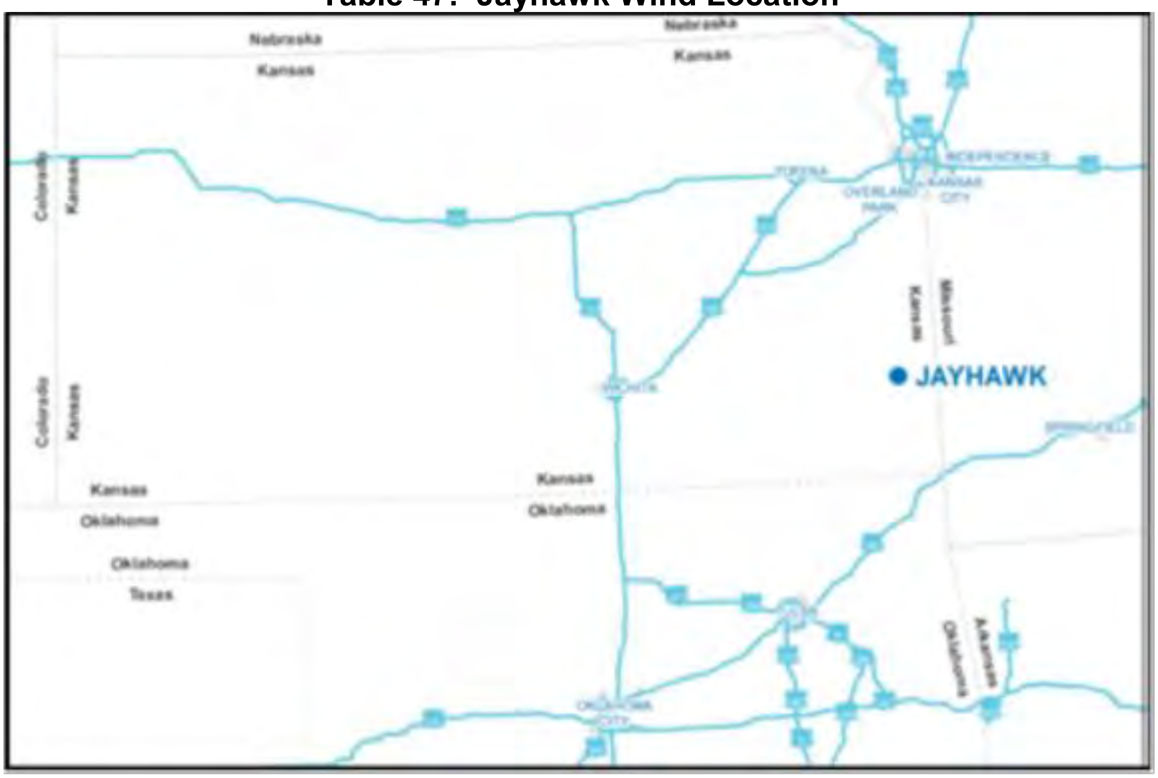


Jayhawk Wind is a 193.2 MW wind energy development with Evergy being the energy off-taker of 155 MW of the facility. The facility is currently planned to be in-service 4Q, 2021. Jayhawk Wind is cited over approximately 21,000 acres in Crawford and Bourbon Counties, Kansas and owned by Apex Clean Energy. Table 46 and Table 47 provide current major milestones and the location of the Jayhawk Wind project.

Table 46: Jayhawk Wind Milestone Activities

Milestone Description	Milestone Dates
Start of Construction	October, 2020
Turbine Deliveries and Erection Begin	June, 2021
Interconnect Facilities Complete	July, 2021
Facility Start-Up Testing	August, 2021
Commercial Operation Date	October, 2021

Table 47: Jayhawk Wind Location



7.3.2 DEMAND-SIDE MANAGEMENT SCHEDULE

Table 48: DSM Program Schedule – Existing Programs

Program Name	Program Type	Segment	Program Implemented	Annual Report	Program Duration	EM&V Completed and draft report available
Energy Saving Products	Energy Efficiency	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Online Home Energy Audit	Educational	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Heating, Cooling & Home Comfort	Energy Efficiency	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	Jan.,2020	90-days following Plan Year	6-Years	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Income-Eligible Home Energy Report	Energy Efficiency	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Residential Demand Response	Demand Response	Residential	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Standard	Energy Efficiency	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Custom	Energy Efficiency	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Process Efficiency	Energy Efficiency	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Online Business Energy Audit	Educational	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Smart Thermostat	Demand Response	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Demand Response	Demand Response	C&I	Jan.,2020	90-days following Plan Year	3-Years	1-Yr following Plan Year

Table 49: DSM Program Schedule – Planned Programs

Program Name	Program Type	Segment	Projected Approval Date	Projected Implementation Date	Annual Report
Home Lighting Rebate	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Home Energy Report	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Income-Eligible Home Energy Report	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Online Home Energy Audit	Educational	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Whole House Efficiency	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Income-Eligible Weatherization	Energy Efficiency	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Residential Smart Thermostat w DLC	Demand Response	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Central AC DLC Switch	Demand Response	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Water Heating DLC Switch	Demand Response	Residential	Sep., 2022	Jan., 2023	90-days following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Strategic Energy Management	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Retrocommissioning	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Block Bidding	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Online Business Energy Audit	Educational	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Small Business Targeted	Energy Efficiency	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Business Smart Thermostat w DLC	Demand Response	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year
Demand Response Incentive	Demand Response	C&I	Sep., 2022	Jan., 2023	90-days following Plan Year

7.3.3 EVALUATION, MEASUREMENT AND VERIFICATION

Evergy Missouri Metro will prepare a request for proposal (“RFP”) to conduct an evaluation, measurement and verification (“EM&V”) of all demand-side programs and demand-side rates that are approved by the Commission.

EM&V Process and Impact

20 CSR 4240-20.093 (8) states that each electric utility shall hire an independent contractor to perform and report Evaluation Measurement & Verification (EM&V) of each commission approved demand-side program in accordance with 4 CSR 240-20.094 Demand-Side Programs.

EM&V Process Evaluation

The scope of work for the RFP will require that the Vendor conduct a process evaluation pursuant to requirements of 20 CSR 4240-22.070 (8) (A) and require the Vendor to provide answers to questions 1 through 5 of this rule section in the EM&V final report (“Report”).

EM&V Impact Evaluation

The scope of work for the EM&V RFP will require that the Vendor conduct the impact evaluation pursuant to requirements of 20 CSR 4240-22.070 (8) (B). The Vendor shall develop methods of estimating the actual load impacts of each demand-side program to a reasonable degree of accuracy.

EM&V Data Collection

The scope of work for the EM&V RFP will require that the Vendor collect EM&V participation rate data, utility cost data, participant cost data and total cost data pursuant to requirements of 20 CSR 4240-22.070 (8) (C).

EM&V Reporting Requirements

The scope of work for the EM&V RFP will also require that the Vendor perform, and report EM&V of each commission-approved demand-side program to be completed on a schedule approved by the commission at the time of demand-side program approval s in accordance with 4 CSR 240-20.094(4).

The EM&V RFP will require the selected vendor to evaluate and prepare an annual program performance report. Preliminary EM&V reports will be available approximately 90 days following the end of the program year. Commission Staff and stakeholders will be provided with an opportunity to review, and comment on the draft report. The final EM&V report will be available approximately 180 days following the completion of each program year. The full EM&V will be conducted over the three-year cycle with annual performance reports delivered each year.

EM&V Schedule and Budget

The EM&V budget shall not exceed five percent (5%) of the total budget for all approved demand-side program costs. A tentative EM&V schedule is shown in Table 50 below.

Table 50: Evaluation Schedule[1]

Estimated EM&V Schedule	
1st Annual EM&V Begins	Day 1 of PY 1
1st Annual Draft Report	90 days after the end of PY 1
1st Annual Program Report	180 days after the end of PY 1
2nd Annual EM&V Begins	Day 1 of PY 2
2nd Annual Draft Report	90 days after the end of PY 2
2nd Annual Program Report	180 days after the end of PY 2
3rd Annual EM&V Begins	Day 1 of PY 3
3rd Annual Draft Report	90 days after the end of PY 3
3rd Annual Program Report	180 days after the end of PY 3

SECTION 8: SPECIAL CONTEMPORARY ISSUES

From the Commission Order, EO-2020-0046, the following Special Contemporary Resource Planning Issues are addressed as follows:

8.1 UNCERTAIN FACTORS

When complying with 4 CSR 240-22.060(5)(M), include the following as uncertain factors that may be critical to the performance of alternative resource plans:
(1) Foreseeable demand response, including, but not limited to, aggregation and development of technologies such as integrated energy management control systems, linking smart thermostats, lighting controls, and other load-control technologies with smart end-use devices;
(2) Foreseeable energy storage; and
(3) Foreseeable distributed energy resources, including, but not limited to, distributed solar generation, distributed wind generation, combined heat and power (CHP), and microgrid formation. Develop and provide a database of information on distributed generation (both utility owned and customer owned) and distributed energy storage (both utility owned and customer owned) for purposes of evaluating current penetration and planning for future increases in levels of distributed generation and energy storage.

Response:

The Company has reviewed developing technologies such as integrated energy management control systems, energy storage technologies, and distributed resources and at this time they are not to the point where they would have a material impact on the selection of a preferred plan. These emerging technologies will continue to be reviewed in future annual updates and triennial planning. The demand-side technologies are reviewed as part of the DSM potential evaluation process, and this is being updated for the 2021 Triennial Filing. Energy storage is reviewed as part of the technology screening process and the impact of distributed energy resources is reviewed and included in the load forecasting process. In addition, the Company is currently conducting a behind-the-meter solar and energy storage potential study. Results are expected in the Summer 2020 and will be included as part of the 2021 IRP.

8.2 <u>ELECTRIC VEHICLE USAGE</u>

When complying with 4 CSR 240-22.060(5)(A), analyze and document the impact of electric vehicle usage for the 20-year planning period upon the low-case, base-case and high-case load forecasts.

Response:

The Electric Power Research Institute ("EPRI"), tracks electric vehicle (EV) sales and develops national and regional EV adoption projections. Through the Company's participation in the EPRI's Transportation Electrification research program, EPRI developed Low, Medium, and High EV adoption scenarios for each Company service territory:

Low Adoption: This scenario represents how EV adoption may grow if battery costs remain high, regulations that drive EV sales are canceled, and incentives are reduced.

Medium Adoption: This scenario represents how EV adoption may grow if policies and incentives remain positive and a moderate level of charging infrastructure is deployed.

High Adoption: This scenario represents how EV adoption may grow if policy drivers increase, battery and EV costs decline, and substantial incentives for support infrastructure.

With Evergy's deployment of the Clean Charge Network (CCN), the EV sales in the Kansas City region are currently trending along EPRI's Medium scenario projection.

Each EV adoption scenario was incorporated into the corresponding Company low, base, and high energy and demand forecasts presented in Volume 3 of this report. As the projected increase in electrical load, due to EV adoption, are incorporated in the load forecasts, they have been addressed in the selection of the preferred plan.

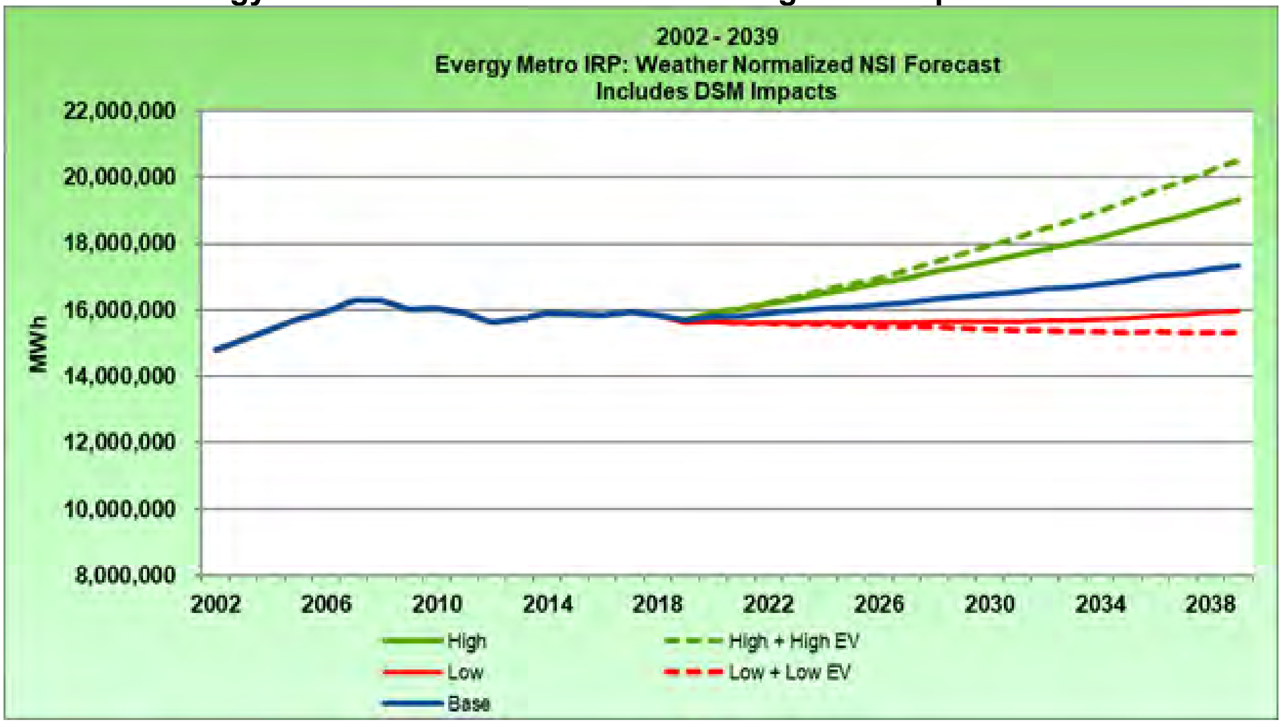
In the Evergy MO West base case load forecast, EV MWh usage adds less than 0.1% to annual usage in 2020, but grows significantly thereafter, representing 0.9% of annual usage by 2029 and 3.1% by 2039, adding ~300k MWh to the base case forecast in 2039.

In the Evergy MO Metro base case load forecast, EV MWh usage adds 0.2% to annual usage in 2020, but grows significantly thereafter, representing 1.4% of annual usage in 2029 and 4.4% of annual usage in 2039, adding ~700k million MWh to the base case forecast in 2039.

EPRI also conducted an analysis of the impact of EV adoption and valuation of the CCN for the Company. The EPRI analysis of generation and transmission level system impacts suggests that the Company bulk power system can support a significant level of PEV adoption and that EV charging, if unmanaged, would have the greatest impact during the late afternoon system peak load hours. The analysis shows that with managed home charging, the peak capacity needed is significantly less than what might be needed in the case of unmanaged charging.

Subsequent refinement of the analysis by EPRI and the Company, estimate that the system level impact of unmanaged EV charging will be 1.0-1.25 kW per EV. However, if charging is aggressively managed with TOU rates for home charging and demand response or active charge management is used to manage workplace and public charging this system level impact could be as low as 0.25 kW per EV. The Company load forecast currently models the EV energy usage as other base, non-weather related load with a demand impact of about 0.8 kW per EV.

Table 51: Evergy Metro NSI forecast with Low & High EV adoption scenarios



8.3 TRANSMISSION GRID UPGRADES

Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from likely future retirements of any existing coal-fired generating unit in the time period established in the IRP process.

Response:

Evergy has evaluated the cost of transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from likely future retirements of any existing coal-fired generating unit in the time period established in the IRP process by running steady-state and transient stability analysis on multiple future years and seasons. However, because the retirement of larger coal-fired generators would necessitate the replacement of that supply with another resource and, at this time, we are not aware of the location of that replacement supply, these upgrades or additions could change or be eliminated altogether. The estimates provided for these upgrades are high-level estimates and are subject to change based on further analysis. The identified upgrades or additions are shown in Table 52 below.

Table 52: Identified Transmission Upgrades

Solution	Area	Hawthorn 5	LaCygne 1	LaCygne 2	LaCygne Plant	Lawrence 4	Lawrence 5	Lawrence Plant	Jeffrey 3	Jeffrey Plant	All Plants
		Upgrade Costs (in Millions) Associated with Unit / Plant Retirement Scenarios									
Lake Winnebago-Pleasant Hill 161kV 1954 Amp	Evergy Missouri West	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10
115kV SVCs	Evergy Kansas Central					$ 28.80	$ 28.80	$ 28.80	$ 28.80	$ 28.80	$ 28.80
Add second 10 MVAR Step on Tioga 69kV Cap Bank	Evergy Kansas Central		$ 1.20	$ 1.20	$ 1.20				$ 1.20		
Add Second Step on Norton Reactor	Evergy Metro									$ 3.00	$ 3.00
Brunswick - Carrolton 161kV Replace Switches and CTs	Evergy Metro									$ 3.50	$ 3.50
Craig - Lenexa CKT 2 161kV Line Rebuild	Evergy Metro	$ 6.85									$ 6.85
Hoyt 115kV SVC/STATCOM	Evergy Kansas Central	$ 7.80									$ 7.80
LaCygne 70 MVAR Shunt Reactor	Evergy Metro				$ 25.00						
Lenexa - Shawnee Mission 161kV Line Rebuild	Evergy Metro	$ 5.85									$ 5.85
North KC - Navy 161kV	Evergy Metro		$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
Rebuild Tecumseh Hill - Stull 115kV to 1200 Amps	Evergy Kansas Central							$ 17.00			
Relocate Sibley Plant - Duncan Road 161kV to Sibley 161kV	Evergy Missouri West									$ 7.60	$ 7.60
Summit 115kV SVC	Evergy Kansas Central					$ 7.80	$ 7.80	$ 7.80	$ 7.80	$ 7.80	$ 7.80
Upgrade Greenwood - Lee Summit 161kV to 2000 Amp Equipment	Evergy Missouri West	$ 1.50									$ 1.50
Upgrade Midland Transformer to 400 MVA	Evergy Kansas Central	$ 4.50				$ 4.50					$ 4.50
Upgrade Sibley Transformer to 650 MVA	Evergy Missouri West									$ 1.50	$ 1.50
Upgrade Southtown-Martin City 161kV equipment to 1200 Amps	Evergy Metro	$ 0.25								$ 0.25	$ 0.25
Upgrade Stilwell TX-22 (Possibly TX-11)	Evergy Metro	$ 6.00									$ 6.00
Upgrade Western Electric - Longview 161kV to 1200 Amp Equipment	Evergy Missouri West	$ 5.30									$ 5.30
Walnut (Arnold) 115kV SVC	Evergy Kansas Central					$ 7.80	$ 7.80	$ 7.80	$ 7.80	$ 7.80	$ 7.80
Warrensburg 69kV 1200 Amp Upgrade	Evergy Missouri West									$ 8.00	$ 8.00

8.4 GREEN TARIFFS AND COMMUNITY SOLAR

Analyze and assess the use of mechanisms such as green tariffs and community solar to increase the availability of distributed generation for large and small customers.

Response:

The Company believes that the use of green tariffs and community solar provide another option for customers to interact with their energy provider while also providing avenues to potential cost savings. The Company has seen significant interest in the Renewable Energy Rider (otherwise known as Renewables Direct) which will allow large customer to participate with a renewable resource procured on their behalf. In addition, the Company has over 800 customers subscribed, or 66% of the available shares, to its Solar Subscription program. This program has to be 90% subscribed before the array can be built. The Company will also continue to evaluate tariffs (current and new) that utilize distributed generation.

8.5 SECURITIZATION

Analyze and document the prospects for using securitization to advance the retirement of coal generation assets, and channel the savings into more economical investments such as demand-side management, building wind and solar generation, and satisfying corporate renewable energy goals to attract new businesses to the service territory. Securitization is essentially a lower cost, long-term loan that ratepayers take out and pledge to repay using a portion of their future electricity bills using a long-term, lower-cost bond that will save customers money, some of which can be used as new capital.

Response:

Securitization is a financial tool that would create customer-backed commercial bonds through state legislative actions. These bonds would carry a AAA rating. Given such bonds could lower a utility's debt service costs, savings would be created relative to the utility's traditional debt financing. These bonds could be used to recover the remaining net book value of retired or existing generating assets.

For example, given interest rates on commercial AAA rated bonds have averaged approximately 3.77% during March 2019 compared to Evergy Metro's debt cost of approximately 4.93%, Evergy Metro's debt costs could theoretically be lowered by 1.16% on that portion of debt securitized. Assuming that debt is approximately 50% of Evergy Metro's capital structure, a reduction of approximately 0.6% in the pre-tax weighted average cost of capital would be achieved.

Given appropriate state legislation and associated Commission action, securitization could be done with or without plant retirements. Therefore, these savings could be achieved independent of plant retirements. The same holds true for alternative resource investments as well.

8.6 HIGH PERFORMANCE BUILDING HUB

Analyze and assess the benefits of supporting the development and funding of a High Performance Building Hub to address information and financing (including bridge financing for project development) for building owners – especially affordable housing. Look at Building Energy Exchange (an informational resource for the building industry in New York) and NYC Energy Efficiency Corporation (a specialty financing corporation) as possible models.

Response:

Evergy as part of their efforts to engage and influence the local design, build industry and real estate development market participated, sponsored and hosted several events during MEEIA Cycle 2. Local partners and organizations of note include; U.S. Green Building Council, Society of Industrial and Office Realtors-Western Missouri/Kansas Chapter, Show Me PACE, Metro Wire Media and the St. Joseph Construction Association. In an effort to build on the momentum from Cycle 2 the company solicited as part of its MEEIA Cycle 3 vendor request for proposal (RFP) several alternative financing solution firms. The intent behind this effort is to identify a list of turnkey service providers and create a specialized network that the Company can link customers and market actors to address financing for holistic energy savings projects. Vendors of note serving both the commercial and industrial (C&I) and income eligible segment include; Empower Equity, HBC Financial and Redaptive.n short, the Company sees the benefits of supporting the continued engagement of high performance building and alternative financing solutions to address market barriers. The Company has made great strides over the past few years and will continue to research, analyze and engage with best in class solutions providers and stakeholders in this space as part of the MEEIA Cycle 3 deployment and beyond.

8.7 SELF-SCHEDULING PRACTICES IN THE RTO MARKET

Staff's report in EW-2019-0370 regarding its investigation of utility self-scheduling practices in the RTO market concluded that ratepayers were not being "actively harmed" by the practice of self-scheduling, but admitted that Staff lacked the data and resources to answer the fundamental questions of whether Missouri utilities are bidding into the markets at below production costs or otherwise harming ratepayers through "increased outage rates, decreased off-system sales revenue, increased operations and maintenance costs, shortened life of assets, increased outage frequency, decreased reliability, increased LMPs at the load node, and/or generally increased energy prices across the RTO's footprint" (Staff Report at 13). EMW shall address these issues in its annual update since only it possesses the necessary bid formulation and production cost data.

Response:

The Company is working directly with Staff to finalize a document for tracking instances of self-committed generation resources in the SPP market through the annual Prudence Audit process. The true impact of self-committed resources can't be analyzed by the Company as we do not have knowledge of other market participant's intentions and we do not have the ability to fully model the SPP system. The tracking document will provide a snapshot of information at the time of any self-commitment.

8.8 ELECTRIC VEHICLE CHARGING INFRASTRUCTURE

Analyze and screen electric vehicle charging infrastructure as a candidate resource option.

Response:

In January 2015, the Company launched the CCN, an initiative to install and operate just over 1,000 EV charging stations throughout the Greater Kansas City region and within the Company service territories. As of Feb 1, 2020, the Company has installed 971 AC Level 2 charge stations and 23 DC fast charge ("DCFC") stations at 348 Company and host locations to support the growing market of electric vehicles ("EVs"). The Company has placed, 437 stations in Evergy MO Metro, 264 stations in Evergy MO West, 277 stations in Evergy KS Metro, and 16 stations in Evergy KS Central.

During the same period the number of EVs registered in the Company service territories has increased from 1,116 in 2015 to 6,701 as of September 2019. According to EPRI's most current Medium adoption scenario, there could be approximately 430,000 EVs registered across all Evergy service territories in 2039. This represents a significant amount of mobile battery storage capacity that has the potential be a significant grid resource.

One potential application of EVs that continues to be explored is "vehicle-to-grid" (V2G) or bi-directional energy flow between the vehicle and the grid. For a device capable of returning energy to the electric grid, there are a number of potential services the device can provide the grid. The value of these services is strongly dependent on the speed of response, energy capacity, and power capacity of the vehicle; and grid conditions at the specific geographic location where the vehicle is connected to the grid. Implementation of V2G requires that the grid condition(s) being supported by V2G be known and communicated to the vehicle in real time so that the vehicle's systems can provide controlled power flow back to the grid as needed. EPRI provided the Company an overview of V2G technology and it current state of commercial viability.

While several pilots have and are being conducted to demonstrate the technical feasibility of V2G capabilities, there remain technical, systematic, regulatory and cost effectiveness hurdles to widespread use of V2G and its potential use as a grid resource. Evergy will continue to monitor the status and commercial viability of V2G technologies.

Like V2G, "vehicle-to-home" or V2H is another potential application for EV. Here the PEV is used as a backup energy supply for a home, business, or other local electric load. In this application, the vehicle only provides electricity in isolation from the grid as is currently done with backup generators. Nissan and Mitsubishi have both conducted public demonstrations of V2H systems in Japan, the United States, and Europe, but to date, no automaker or charge station vendor has released such hardware for public sale and consumer use. One concern that is common with V2G and V2H is understanding the impact on the vehicle's mobility while providing auxiliary services and the impact on battery life.

While much of the industry research is focused on developing V2G capabilities, managed charging or V1G (one-way energy flow between the vehicle and the grid) functions can transform the EV into a flexible load that it can be leverage as a grid resource by managing when the charging occurs and at what rate of charge. Managed charging can be as simple as charging the vehicle on a set time schedule or by responding to external control signals from a local energy management system or the utility or a combination of time schedule and remote control.

With the Company's system peak occurring in the late afternoon, home charging could have substantial system peak coincidence and cause localized overloading of the distribution grid. While not a direct control method, time-of-use (TOU) rates can be used to influence consumer charging behavior and could be viewed as a charge management method. The Company is first addressing the potential system impact of EV drivers charging at home by introducing a Residential TOU rate designed to incentivize EV drivers to charge their vehicles during off-peak periods during the late-night hours.

The CCN is a managed network of charging stations and the ChargePoint platform provides the Company the ability to reduce or eliminate charging during periods of peak demand. The Company will incorporate the CCN in the Company's demand response program and issue charge reduction events from its Distributed Energy Resource Management System (DERMS) in conjunction with the other demand response programs. The ChargePoint platform also provides the capability to apply charge reduction events to the entire network, to a group of stations on a feeder that is at a critical load level, or to individual charging stations. The Company plans to evaluate and implement charge reduction in a manner that will continue to provide some level charge to the EV to minimize the impact on driver experience.

EPRI has an active project with several utilities and EV manufactures to develop a platform that would allow utilities to manage EV charging by communicating directly to the EV through the EV's on-board telematics system. Called the Open Vehicle Grid Integration Platform (OVGIP), this is a cloud-based computer service that would allow utility grid state and EV information to be exchanges with a large number of vehicles through a single communications path from the utility to the platform. The OVGIP would in turn use multiple paths to reach the connected vehicles via each EV manufacture telematics platform. Evergy will continue to monitor the status and when the OVGIP or similar platform become commercial available, may explore a potential charge management pilot using this technology.

8.9 RENEWABLE ENERGY/BATTERY STORAGE VS EXISTING COAL-FIRED GENERATION

Analyze, document and screen renewable energy + battery storage as an alternative to existing coal-fired generation.

Response:

In December 2018, Evergy issued a Request for Proposal (RFP) for renewable generation offers including battery storage. Battery storage was paired with a few solar responses received. Standalone solar generation has estimated capacity factors between ~25 %- 34% in the SPP region. Current battery storage technology has a maximum capability of 4 hours of storage with a 3:1 storage ratio meaning for a 240 MW nameplate solar facility, the storage system would be sized around 70 MW. Current estimated costs for adding storage to a solar facility increase the solar project cost by approximately 30% - 60%. Comparing a new solar facility plus storage to an existing coal facility in terms of costs isn't logical as an existing coal plan is already in production as well as included in customer rates and has been depreciating since it went into service. Additionally, comparison of a coal facility vs solar isn't realistic operationally because coal generation isn't dependent on time of day and weather conditions as solar is. Coal generation energy output far outweighs the energy output from the same sized solar facility.

However, the Company did evaluate the merits of both solar and coal plant retirements. Both solar additions and coal plant retirements were found to be economic under certain scenarios. Given that solar was found to be economic under more scenarios than not and therefore reduces the expected value 20-year NPVRR, Evergy has announced in this IRP filing the anticipated addition of 500 MW of solar in 2023. An RFP is anticipated to be issued in 2020 to gather updated cost and operating data to further refine the assumptions used in the 2020 Annual Update filings. Responses to this RFP will likely include combined solar and battery offers and will be evaluated at that time.

8.10 MUNICIPAL AND CORPORATE RENEWABLE ENERGY GOALS

Analyze and develop as candidate resource options the satisfaction of municipal and corporate renewable energy goals, particularly the plan of the City of Kansas City, which when enacted into law by ordinance may become a legal mandate within the meaning of 4 CSR 240-22.060(3)(A).

Response:

The Company supports municipalities and corporations in meeting their renewable energy goals. This includes determining if the aggregate interest is large enough to justify a commitment to a specific resource for use in a tariff program or in a special contract. The Company currently offers a way for small and large businesses to offset a percentage of their energy usage with renewable energy through the Company's Renewables Direct program (see link below). In addition, the Company may choose to work with municipal and corporate customers to achieve specific renewable energy goals through energy offsets. However, helping customers meet their renewable goals does not meet the definition of candidate resource option in 20 CSR 4240-22.020(3). https://www.evergy.com/smart-energy/renewable-resources/renewables-direct.

8.11 ENVIRONMENTAL CAPITAL AND OPERATING COSTS FOR COAL-FIRED GENERATING UNITS

Analyze and document the future capital and operating costs faced by each KCP&L coal-fired generating unit in order to comply with all existing, pending, or potential environmental standards, including:

Response:

(1) ***Clean Air Act New Source Review provisions:*** The Company reviews proposed generation projects and permits these projects, as necessary, to comply with rule.

(2) ***1-hour Sulfur Dioxide National Ambient Air Quality Standard:*** The Company is in compliance with this rule.

(3) ***National Ambient Air Quality Standards for ozone and fine particulate matter:*** The Company is in compliance with this rule.

(4) ***Cross-State Air Pollution Rule;***

The Company will comply through a combination of trading allowances within or outside its system in addition to changes in operations as necessary.

(5) ***Mercury and Air Toxics Standards:*** The Company is in compliance with this rule.

(6) ***Clean Water Act Section 316(b) Cooling Water Intake Standards:*** See Table 53, Table 54, and Table 55.

(7) C***lean Water Act Steam Electric Effluent Limitation Guidelines:*** See Table 53, Table 54, and Table 55.

(8) ***Coal Combustion Waste rules using cost of removal as well as cap-and-cover; and*** See Table 53, Table 54, and Table 55.

(9) ***Clean Air Act Regional Haze Requirements:*** The Company is in compliance with this rule.

Table 53: Environmental Capital Cost Estimates ** Confidential**

Environmental Retrofit Technology Capital Cost (2019 $ x Millions)	LaCygne 1 and 2[1]	Hawthorn	Iatan 1[1]
CWA 316(b)/Fish Intake-Screens	[redacted]		
ELG-CCR/Ash Conversion			

Notes
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act
[1] Evergy Metro's Share

Table 54: Retrofit Fixed O&M Estimates ** Confidential**

Environmental Retrofit Technology Fixed O&M ($/kW - 2019 $)	LaCygne 1 and 2	Hawthorn	Iatan 1
CWA 316(b)/Fish-Friendly Screens	[redacted]		
ELG-CCR/Ash Conversion			

Notes
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act

Table 55: Retrofit Variable O&M Estimates ** Confidential**

Environmental Retrofit Technology Variable O&M ($/MWh - 2019 $)	LaCygne 1 and 2	Hawthorn	Iatan 1
CWA 316(b)/Fish-Friendly Screens	[redacted]		
ELG-CCR/Ash Conversion			

Notes
ELG = Effluent LimitatiionGuidelines
CCR = Coal Combustion Residual Rules
CWA = Clean Water Act

8.12 COMPARISON OF UTILITY SCALE WIND AND SOLAR RESOURCES TO OTHER SUPPLY-SIDE ALTERNATIVES

Analyze and document cost and performance information sufficient to fairly analyze and compare utility scale wind and solar resources, including distributed generation, to other supply side alternatives.

Response:

The Company's Supply Side Analysis in the 2018 IRP filing (Volume 4) included an analysis of utility scale wind and solar resources and other distributed generation alternatives including solar, fuel cells, landfill gas, battery storage.

Customer installed solar distributed generation is incorporated in the Company's residential and commercial end use forecasts presented in Section 2 of this report. Starting with the 2013 base year forecast, the Company began tracking solar installations and merged that tracking with the EIA forecast estimate in 2015 to start generating a solar end-use intensity forecast for use in our residential and commercial forecasts.

As part of this IRP Update, Alternative Resource Plans were evaluated that included additional wind and solar resources. As discussed elsewhere in this report, Evergy has plans to pursue the addition of 500 MW of solar to be in service in 2023.

8.13 EMERGING ENERGY EFFICIENCY TECHNOLOGIES

Analyze the impact of emerging energy efficiency technologies throughout the planning period.

Response:

The Demand Side Resources Analysis was based on 2017 DSM Potential Study conducted by Applied Energy Group (AEG). AEG maintains an extensive database of existing and emerging measures for their studies. Their database draws upon reliable sources including the California Database for Energy Efficiency Resources (DEER), the EIA Technology Forecast Updates – Residential and Nonresidential Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data. Therefore, the impact of emerging energy efficiency technologies has been analyzed along with existing technologies in the study. Evergy is currently in the process of conducting a new DSM Potential Study, which will be used for the 2021 triennial filing, where the emerging technologies will be specifically analyzed.