EVERGY MISSOURI WEST

INTEGRATED RESOURCE PLAN

2020 ANNUAL UPDATE

MARCH 2020

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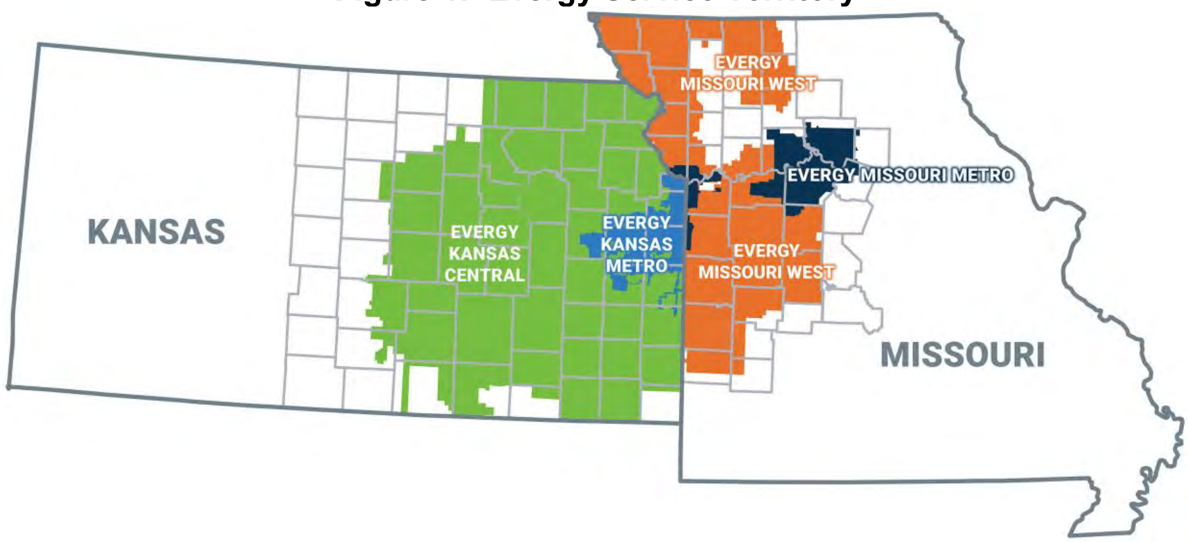
SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Evergy Missouri West ("Evergy West" or "Company") is an integrated, mid-sized electric utility serving portions of Northwest Missouri including St. Joseph and several counties south and east of the Kansas City, Missouri metropolitan area. Evergy West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the entire Evergy service territory which includes Evergy West is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Evergy West 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, estimated retail sales and peak demand based upon 2019 data.

Table 1: Evergy West Customers, NSI and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	**328,464**	**8,133,619**	**1,855**

Evergy West owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 2, Figure 2, and Figure 3 reflect Evergy West's generation assets operating in 2019.

Table 2: Evergy West Capacity and Energy By Resource Type

Capacity By Fuel Type	Capacity (MW)	% of Total Capacity	Annual Energy (MWh)	% of Annual Energy
Coal	462	20.2%	2,058,414	46.4%
Nat. Gas and Oil	1,169	51.1%	249,796	5.6%
Wind	653	28.5%	2,109,622	47.6%
LFG	1.6	0.1%	6,294	0.3%
Solar	3	0.1%	4,545	0.1%
Total	2,289	100.0%	4,428,671	100.0%

* Wind capacity is based upon nameplate

Figure 2: Evergy West Capacity By Resource Type

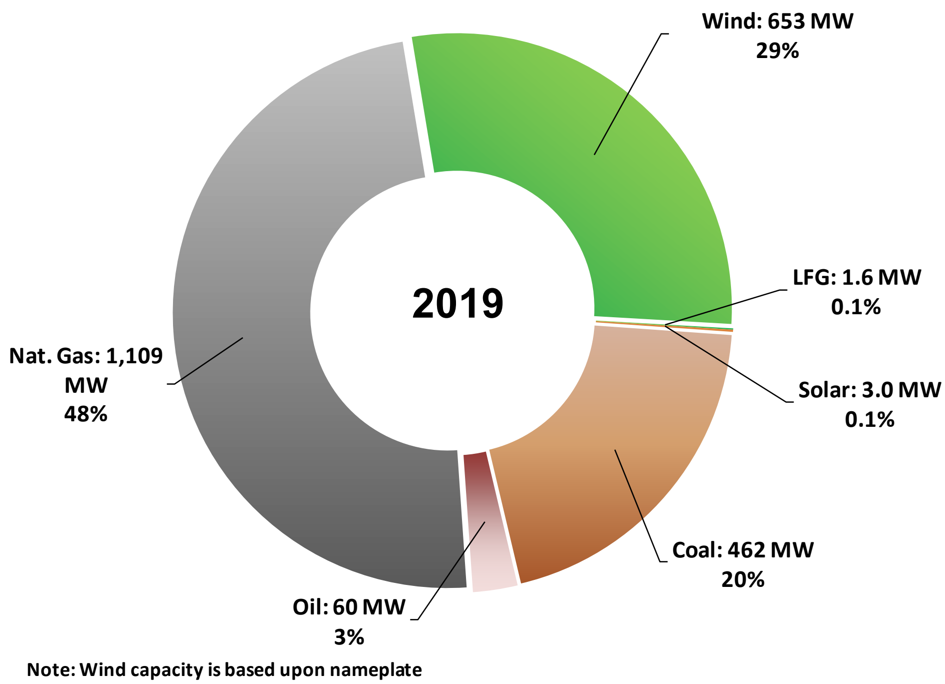
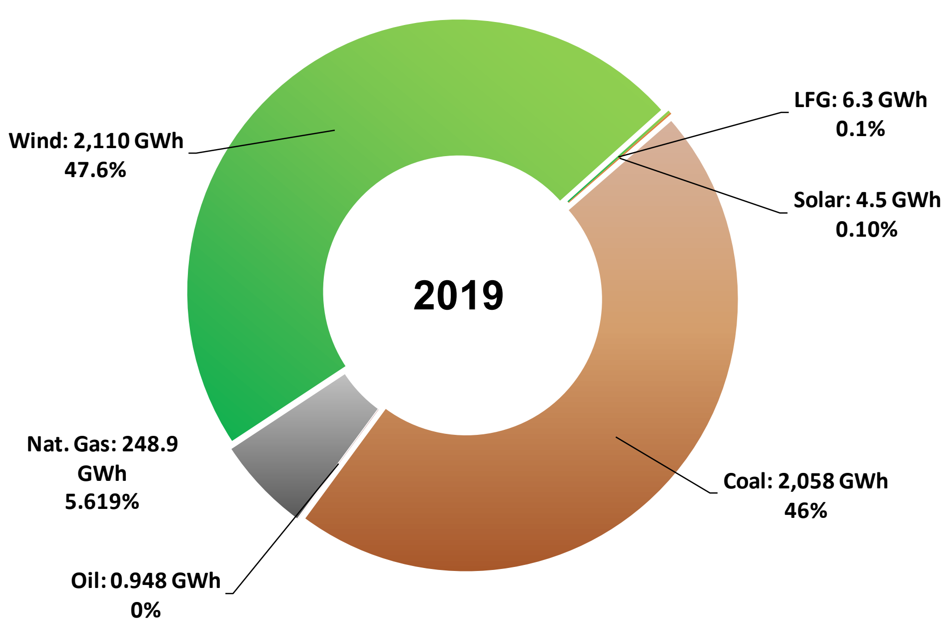


Figure 3: Evergy West Energy By Resource Type



1.2 CHANGES FROM THE 2018 TRIENNIAL IRP

On April 2nd, 2018, KCP&L Greater Missouri Operations Company ("GMO") submitted the triennial compliance filing related to Chapter 22 of the Missouri Public Service Commission ("Commission" or "MPSC") regulations concerning GMO's Electric Utility Resource Planning. The triennial compliance filing made in Case No. EO-2018-0269 consisted of eight sections of material including the "GMO 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 10 MW of solar additions and 266 MW of wind additions from GMO's portion of two power purchase agreements (PPAs) executed in 2017. The Preferred Resource Plan also included retiring 406 MW of coal generation at Sibley Station by 2019 and the 97 MW Lake Road 4/6 natural gas unit by 2020.

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 West and 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-2019-0246 which became effective on August 17, 2019.

The Evergy West (formerly GMO) 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-2018-0269, to the Commission and Parties. The material changes from the April 2018 Preferred Resource Plan were with respect to wind resource additions and the expected retirement date of the 97 MW natural gas unit at Lake Road. All other components including future solar additions and DSM levels 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 included:

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

1.2.1 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			

The 2020 Annual Update analysis includes DSM resources that consist 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.

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 MO West 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 MO West 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 MO West 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 Residential Energy Consumption Survey (RECS) 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 MO West Mid-Case Annual 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**

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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 price, 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 - 2020 Annual 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**

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The following table provides 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 alternatives. The following table compares the all-in cost of the supply side options which includes capital cost, fixed O&M, variable O&M, fuel, and emissions.

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 Missouri West coal-fired generating units. The LAMP program was developed in the late 1980's for the purpose of identifying, evaluating, and recommending improvements and special maintenance requirements necessary for continued reliable operation of Evergy Missouri West 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 Missouri West 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 Missouri West staff, and review and approval of final plan reports. All transmission projects for the Evergy Missouri West 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 Evergy Missouri West. 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

Evergy Missouri West is in the process of implementing targeted Advanced Distribution Technologies (ADT) in its service territory.

Main initiatives in the near-term ADT plan include:

- Fault Location Isolation and Supply Restoration (FLISR) pilots for proof of concept.
- 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 Missouri West 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 Lee’s Summit, Missouri.

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 Missouri location. 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 Missouri West 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 231 CFCIs in the Evergy Missouri West 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 Missouri West 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 Missouri West'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 Missouri West 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 West has filed an application to implement its third MEEIA cycle for Evergy Missouri West. 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 West Cumulative Demand Savings (MW) from MEEIA 3

Year	MEEIA 3 APPROVED	MEEIA 3 IRP MODEL
2020	64	38
2021	83	48
2022	106	64
2023	54	40
2024	57	44
2025	57	43
2026	55	42
2027	54	39
2028	53	36
2029	55	35
2030	49	31
2031	38	24
2032	23	14
2033	16	8
2034	13	5
2035	12	4
2036	11	3
2037	10	3
2038	8	2
2039	5	1

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

Year	MEEIA 3 APPROVED	MEEIA 3 IRP MODEL
2020	46,421	44,850
2021	75,028	65,991
2022	127,702	115,452
2023	128,680	117,052
2024	145,522	136,541
2025	139,360	135,649
2026	132,865	131,686
2027	129,234	125,323
2028	127,584	118,383
2029	129,385	114,301
2030	124,805	107,661
2031	111,043	95,492
2032	89,374	74,299
2033	68,684	51,464
2034	53,584	33,163
2035	40,765	20,291
2036	31,362	13,082
2037	24,407	7,693
2038	18,082	4,679
2039	11,523	3,259

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 West.

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: Evergy Missouri West Cumulative Demand Savings (MW)

Year	RAP-	RAP	MAP
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	83	110	139
2024	94	125	158
2025	105	140	176
2026	116	154	194
2027	127	169	214
2028	139	183	233
2029	146	193	246
2030	153	203	257
2031	159	209	265
2032	164	216	273
2033	169	224	283
2034	176	232	295
2035	182	240	307
2036	189	249	320
2037	196	258	332
2038	201	266	342
2039	207	273	353

Table 15: Evergy Missouri West Cumulative Energy Savings (MWh)

Year	RAP-	RAP	MAP
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	45,538	59,359	76,556
2024	77,073	100,034	128,219
2025	108,905	141,107	180,424
2026	138,884	179,730	229,356
2027	169,497	219,253	285,211
2028	201,075	260,075	340,873
2029	234,236	303,012	399,605
2030	270,003	349,402	462,766
2031	307,214	397,709	528,704
2032	345,261	447,137	596,264
2033	374,947	486,687	651,807
2034	406,273	528,366	711,163
2035	436,392	568,492	768,719
2036	468,413	611,156	829,957
2037	498,987	651,902	887,822
2038	522,445	683,205	933,271
2039	544,751	712,976	976,022

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2018 TRIENNIAL IRP

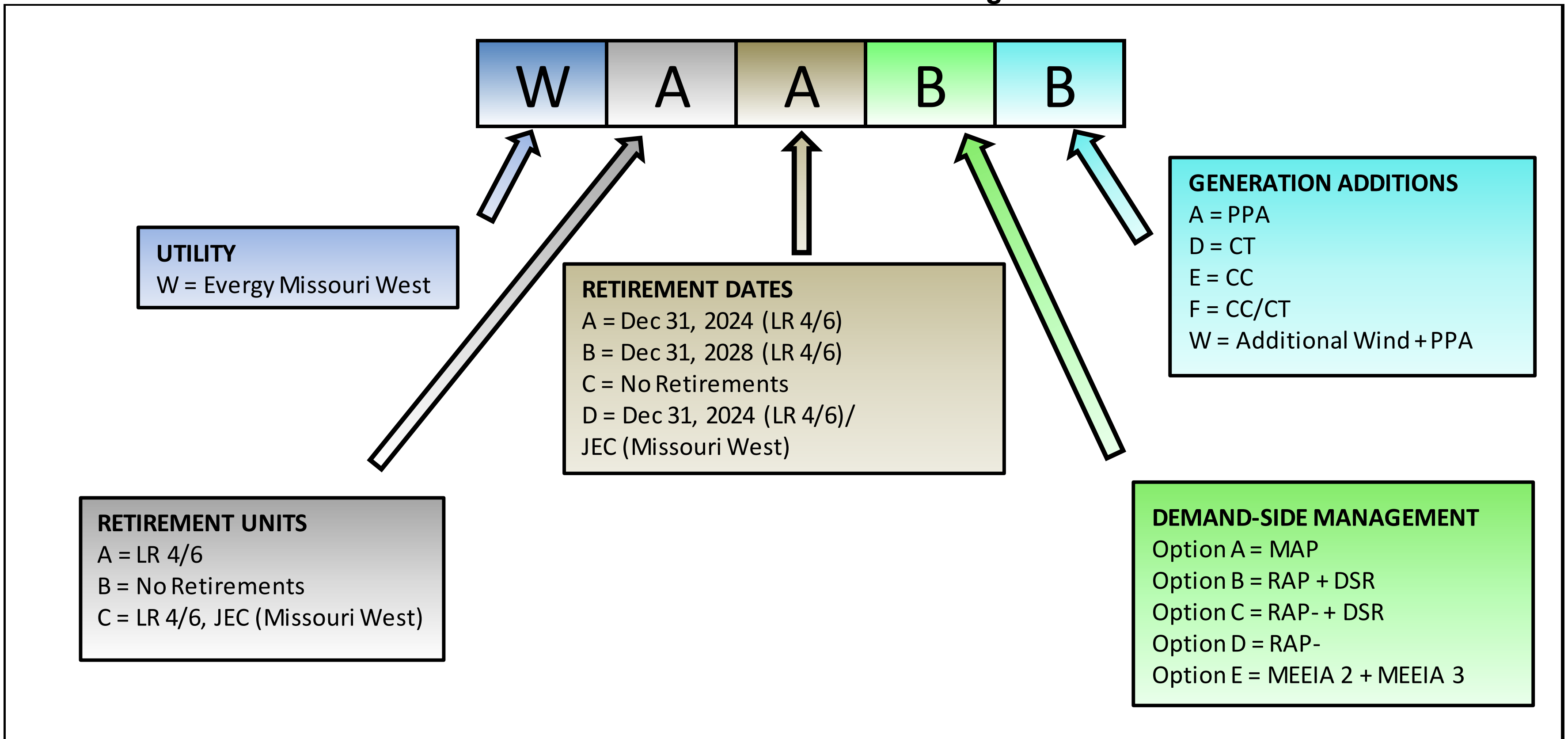
Since the filing of the 2018 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2018 Triennial IRP continue to be the company's path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

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

6.2 ALTERNATIVE RESOURCE PLAN NAMING CONVENTION

Alternative Resource Plans (ARP) 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 provided in Table 17 and Table 18 below.

Table 16: Alternative Resource Plan Naming Convention



Definitions:
LR 4/6: Lake Road 4/6
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MAP: Maximum Achievable Potential
RAP: Realistic Achievable Potential
MEEIA: Missouri Energy Efficiency Investment Act
DSR: Demand-Side Rates

PPA: Power Purchase Agreement
CT: Combustion Turbine
CC: Combined Cycle

Table 17: Alternative Resource Plan Overview

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
WAAAA	MAP	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WAABA	RAP + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WAABD	RAP + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	216 MW CT in 2024 216 MW CT in 2033
WAACA	RAP- + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WAACD	RAP- + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	216 MW CT in 2024 216 MW CT in 2032
WAACE	RAP- + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	351 MW CC in 2024 351 MW CC in 2037
WAACF	RAP- + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	351 MW CC in 2024 216 MW CT in 2037

Table 18: Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
WAACW	RAP- + DSR	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	100 MW Wind in 2022 + PPA
WAADA	RAP-	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WAAED	MEEIA 2 + MEEIA 3	Lake Road 4/6: Dec 31, 2024	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	432 MW CT in 2024 216 MW CT in 2031 216 MW CT in 2037
WABCA	RAP- + DSR	Lake Road 4/6: Dec 31, 2028	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WBCCA	RAP- + DSR	No Retirements	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA
WCDCA	RAP- + DSR	Lake Road 4/6: Dec 31, 2024 JEC 8% (Evergy West)	Solar: 2028 - 10 MW	Wind: 2022 - 125 MW	PPA

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the GMO 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 traditional generation additions. The capacity for 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	WAACA	$10,087.6	$0.0
2	WABCA	$10,089.4	$1.8
3	WBCCA	$10,094.6	$6.9
4	WCDCA	$10,094.8	$7.2
5	WAABA	$10,103.2	$15.5
6	WAACW	$10,113.3	$25.7
7	WAADA	$10,120.6	$33.0
8	WAAAA	$10,209.0	$121.3
9	WAACD	$10,250.3	$162.6
10	WAABD	$10,259.4	$171.8
11	WAACF	$10,283.1	$195.5
12	WAACE	$10,296.0	$208.4
13	WAAED	$10,447.2	$359.5

6.4 PERFORMANCE MEASURES

A summary tabulation of the expected value of all performance measures is provided in Table 20 below. Detailed 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**

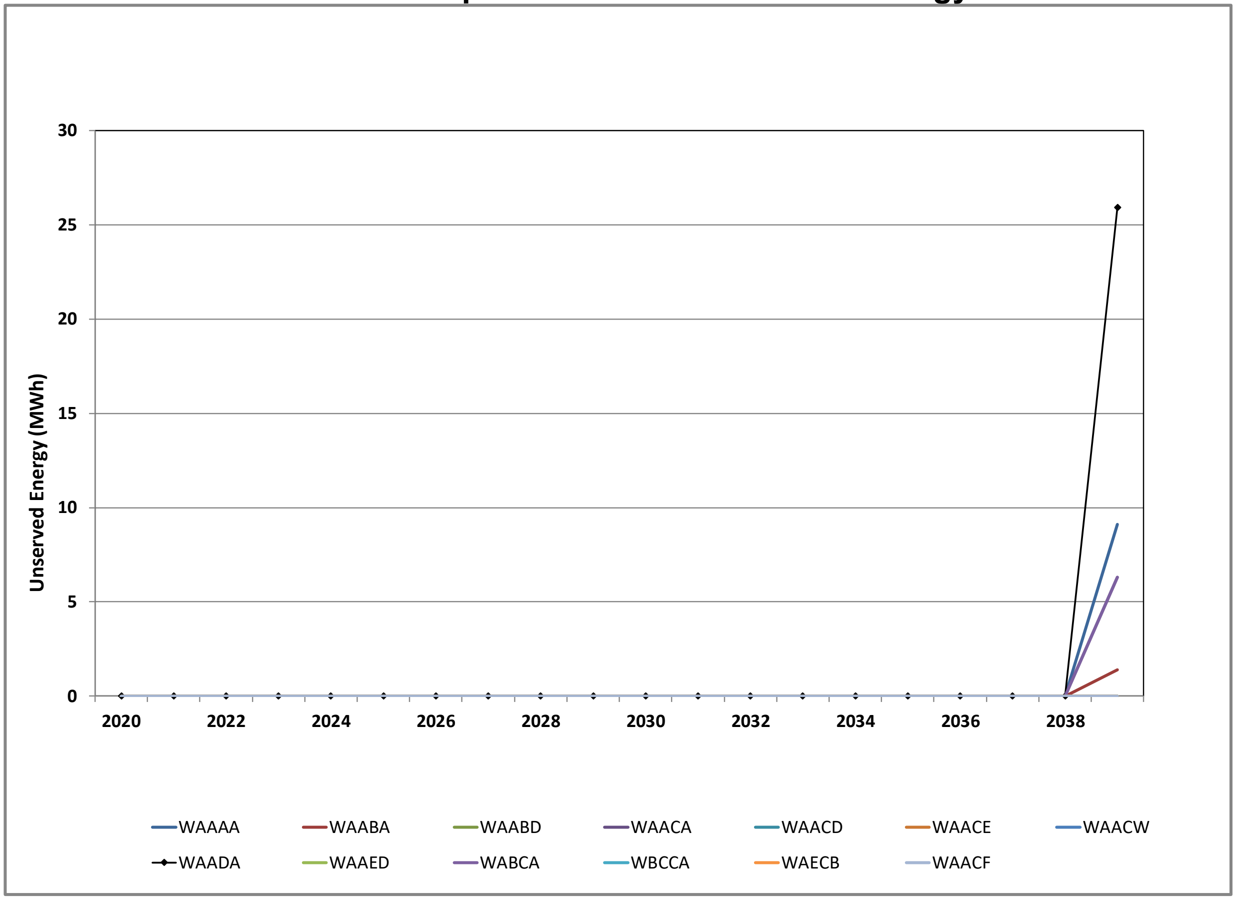
Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Annual Increase
WAACA	10,087.6	[redacted]	[redacted]
WABCA	10,089.4	[redacted]	[redacted]
WBCCA	10,094.6	[redacted]	[redacted]
WCDCA	10,094.8	[redacted]	[redacted]
WAABA	10,103.2	[redacted]	[redacted]
WAACW	10,113.3	[redacted]	[redacted]
WAADA	10,120.6	[redacted]	[redacted]
WAAAA	10,209.0	[redacted]	[redacted]
WAACD	10,250.3	[redacted]	[redacted]
WAABD	10,259.4	[redacted]	[redacted]
WAACF	10,283.1	[redacted]	[redacted]
WAACE	10,296.0	[redacted]	[redacted]
WAAED	10,447.2	[redacted]	[redacted]

C

6.5 UNSERVED ENERGY

The expected value of unserved energy for all GMO Alternative Resource Plans is provided in Table 21 below.

Table 21: Expected Value of Unserved Energy



6.6 JOINT PLANNING EVERGY RESOURCE PLANS

Evergy Missouri West 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 integrated resource analysis 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

Results for each of the joint-planning 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	$65,333.1	$0.0
2	EAAGA	$65,422.8	$89.7
3	EJLGA	$65,453.3	$120.3
4	EKMGA	$65,478.0	$144.9
5	EMOGA	$65,483.8	$150.7
6	ENJGA	$65,493.8	$160.8
7	EMPGA	$65,533.2	$200.1
8	EQPGA	$65,538.1	$205.1
9	EQAGA	$65,560.0	$226.9
10	EDDGA	$65,565.8	$232.7
11	EKPGA	$65,584.3	$251.2
12	ENOGB	$65,587.5	$254.4
13	ECCGA	$65,604.8	$271.7
14	EGRGS	$65,612.4	$279.4
15	ECPGA	$65,624.8	$291.8
16	EPOGB	$65,626.2	$293.1
17	EFQGS	$65,640.4	$307.3
18	EDPGA	$65,662.2	$329.2
19	E8PGB	$65,735.1	$402.0
20	EFQGB	$65,749.6	$416.5
21	EGRGB	$65,749.8	$416.7
22	ESOGB	$65,758.0	$424.9
23	EGRGA	$65,760.4	$427.3
24	E8PGA	$65,767.2	$434.2
25	EFQGA	$65,773.4	$440.3
26	E6PGA	$65,992.2	$659.2
27	EEEGB	$66,558.2	$1,225.1
28	EEEGA	$66,883.0	$1,549.9

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

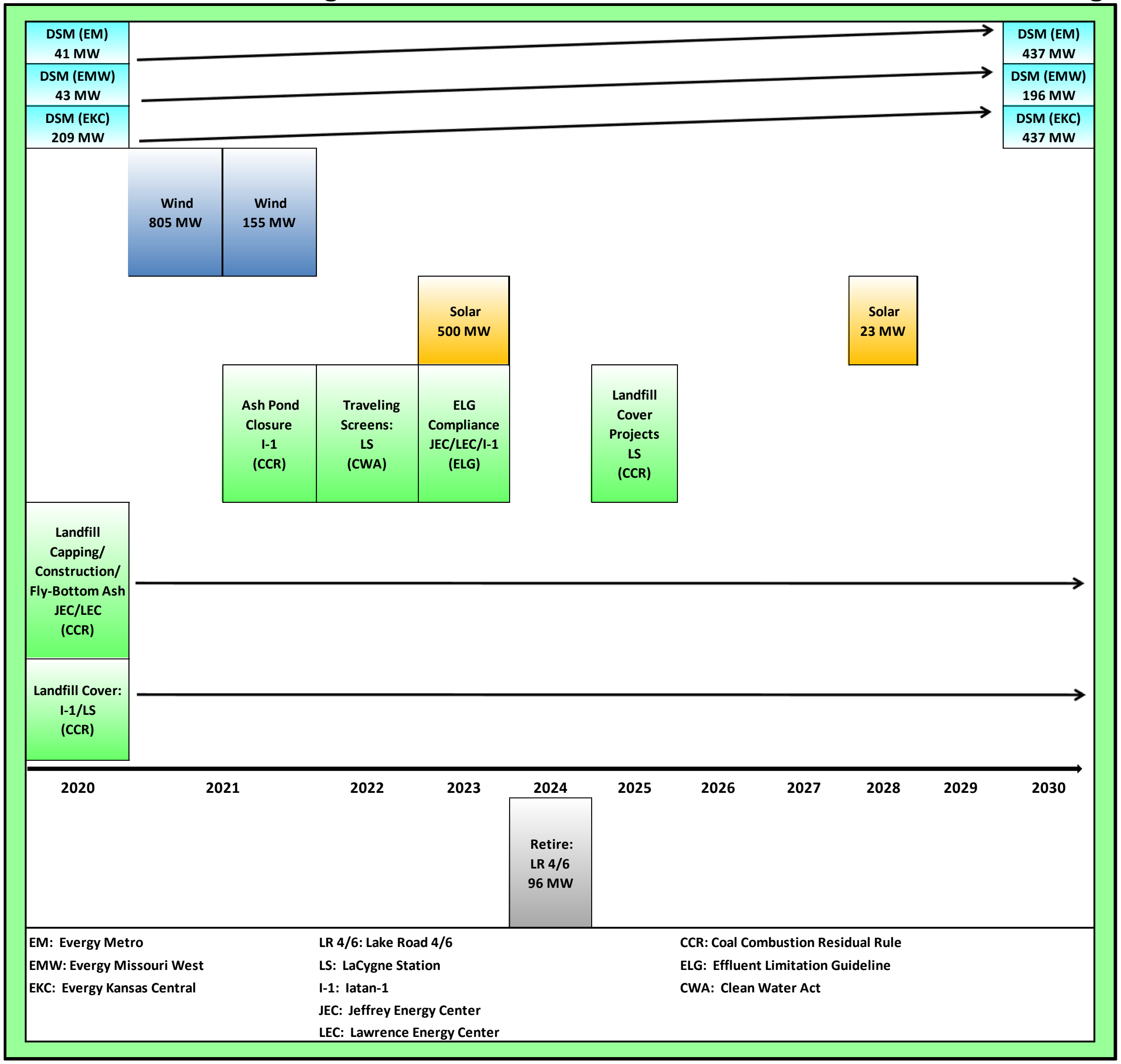
A summary tabulation of the expected value of all performance measures is provided in Table 30 below. Detailed results behind this summary tabulation are attached in Appendix D.

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. This plan is comprised of the following components for years 2020 – 2030 and shown in Figure 4 below.

Figure 4: 2020 Joint-Planning Alternative Resource Plan EAAGS - Years 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]

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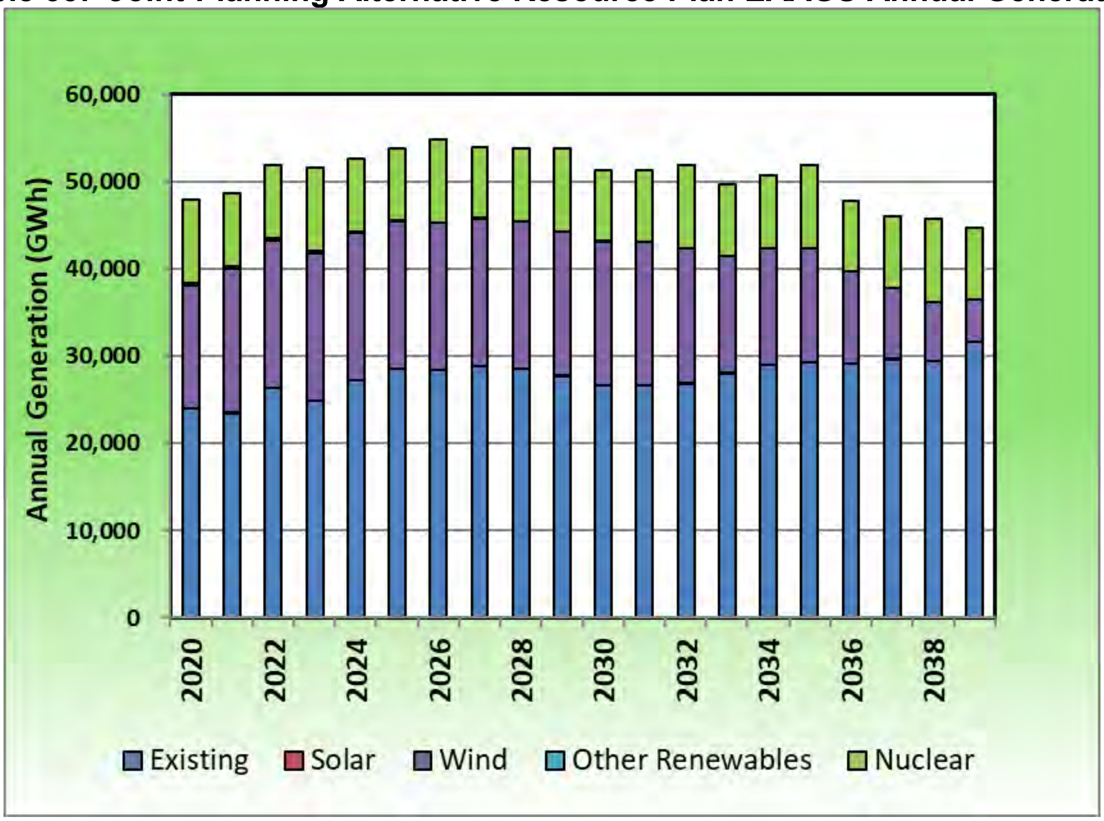
6.8 JOINT-PLANNING ANNUAL GENERATION

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 Combined-Company plans can be found in Appendix C, Generation and Emissions for Each Alternative Resource Plan.

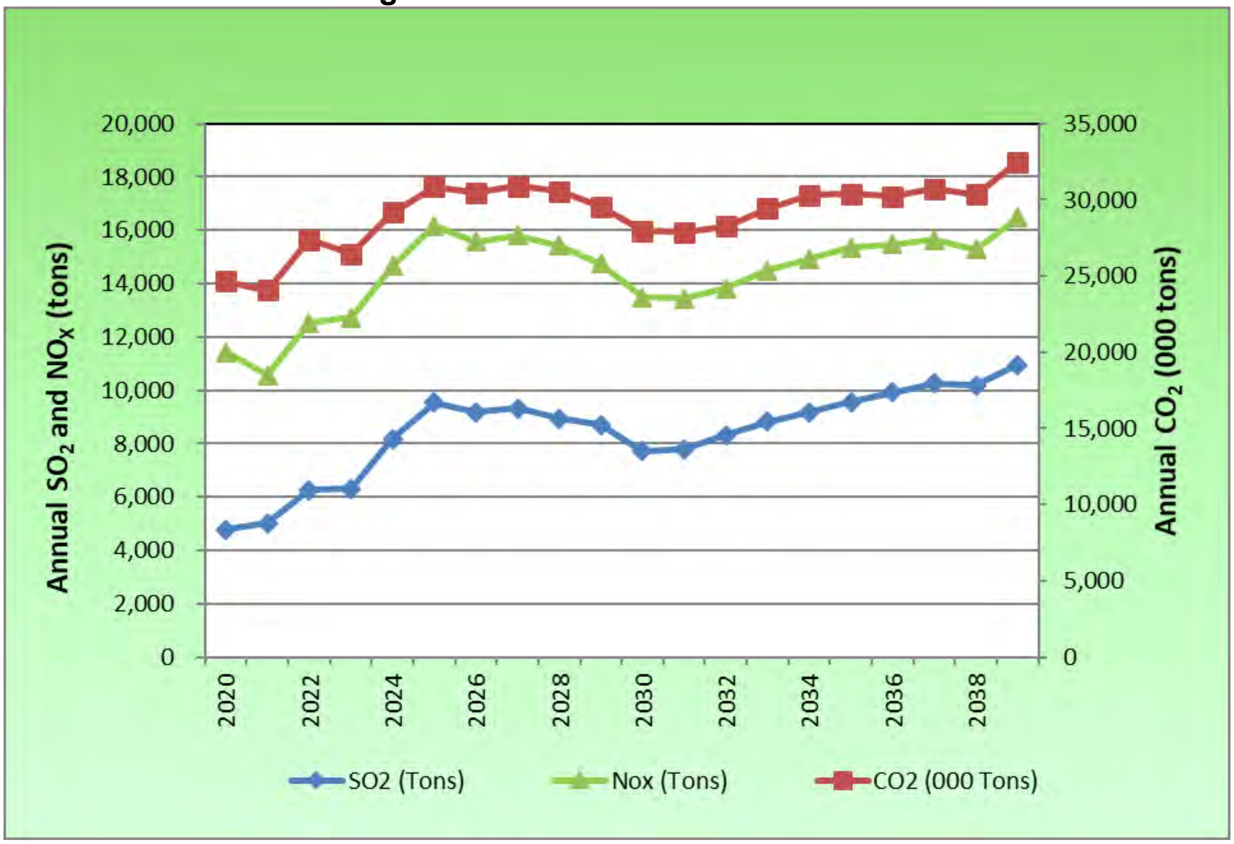
Table 33: Joint-Planning Alternative Resource Plan EAAGS Annual Generation



6.9 JOINT-PLANNING ANNUAL EMISSIONS

The expected value of annual emissions of the Joint-Planning Alternative Resource Plan EAAGS is 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 WAACA as its Preferred Plan, which has the least cost Net Present Value of Revenue Requirement (NPVRR), in 10 of the 18 scenarios used to evaluate the performance of the 13 plans modeled for Evergy Missouri West.

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

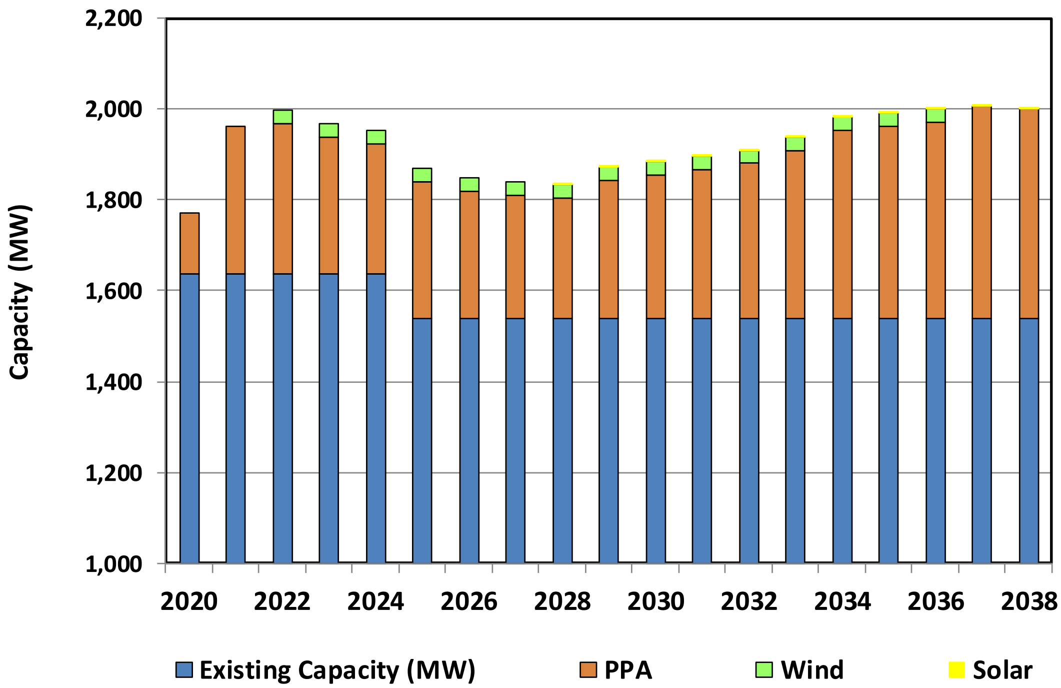
Table 35: 2020 Annual Update Preferred Plan

Year	CT (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)
2020	0			43	
2021	0			57	
2022	0	125		74	
2023	0			108	
2024	0			161	97
2025	0			179	
2026	0			195	
2027	0			213	
2028	0		10	231	
2029	0			242	
2030	0			246	
2031	0			246	
2032	0			245	
2033	0			249	
2034	0			255	
2035	0			261	
2036	0			268	
2037	0			276	
2038	0			291	
2039	0			306	

7.1.1 PREFERRED PLAN COMPOSITION

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

Table 36: Preferred Plan Capacity Composition



The Preferred Plan includes 125 MW of wind addition by 2022 and a 10 MW solar addition by 2028 to meet Missouri RPS requirements. The 125 MW wind addition is currently expected to be Evergy Missouri West'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. The Preferred Plan also includes retirement of Lake Road 4/6 by 2025.

7.1.2 PREFERRED PLAN ECONOMIC IMPACT

The expected value of economic impact by year of the Preferred Plan WAACA 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**

Plan	NPVRR ($mm)	Levelized Annual Rates ($/KW-hr)	Rate Change % by Year
2020	825	[redacted]	[redacted]
2021	848	[redacted]	[redacted]
2022	870	[redacted]	[redacted]
2023	882	[redacted]	[redacted]
2024	887	[redacted]	[redacted]
2025	908	[redacted]	[redacted]
2026	921	[redacted]	[redacted]
2027	946	[redacted]	[redacted]
2028	970	[redacted]	[redacted]
2029	995	[redacted]	[redacted]
2030	1,037	[redacted]	[redacted]
2031	1,059	[redacted]	[redacted]
2032	1,080	[redacted]	[redacted]
2033	1,106	[redacted]	[redacted]
2034	1,141	[redacted]	[redacted]
2035	1,184	[redacted]	[redacted]
2036	1,223	[redacted]	[redacted]
2037	1,278	[redacted]	[redacted]
2038	1,327	[redacted]	[redacted]
2039	1,417	[redacted]	[redacted]

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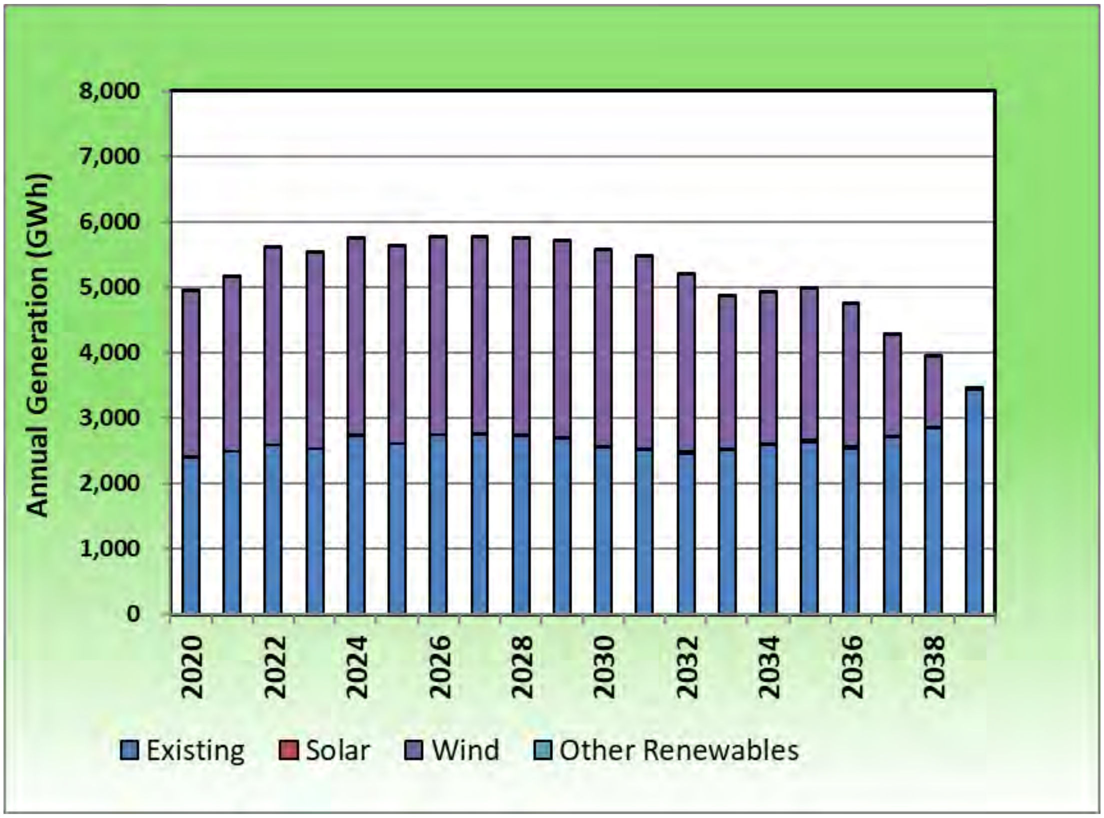
7.1.3 PREFERRED PLAN ANNUAL GENERATION

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

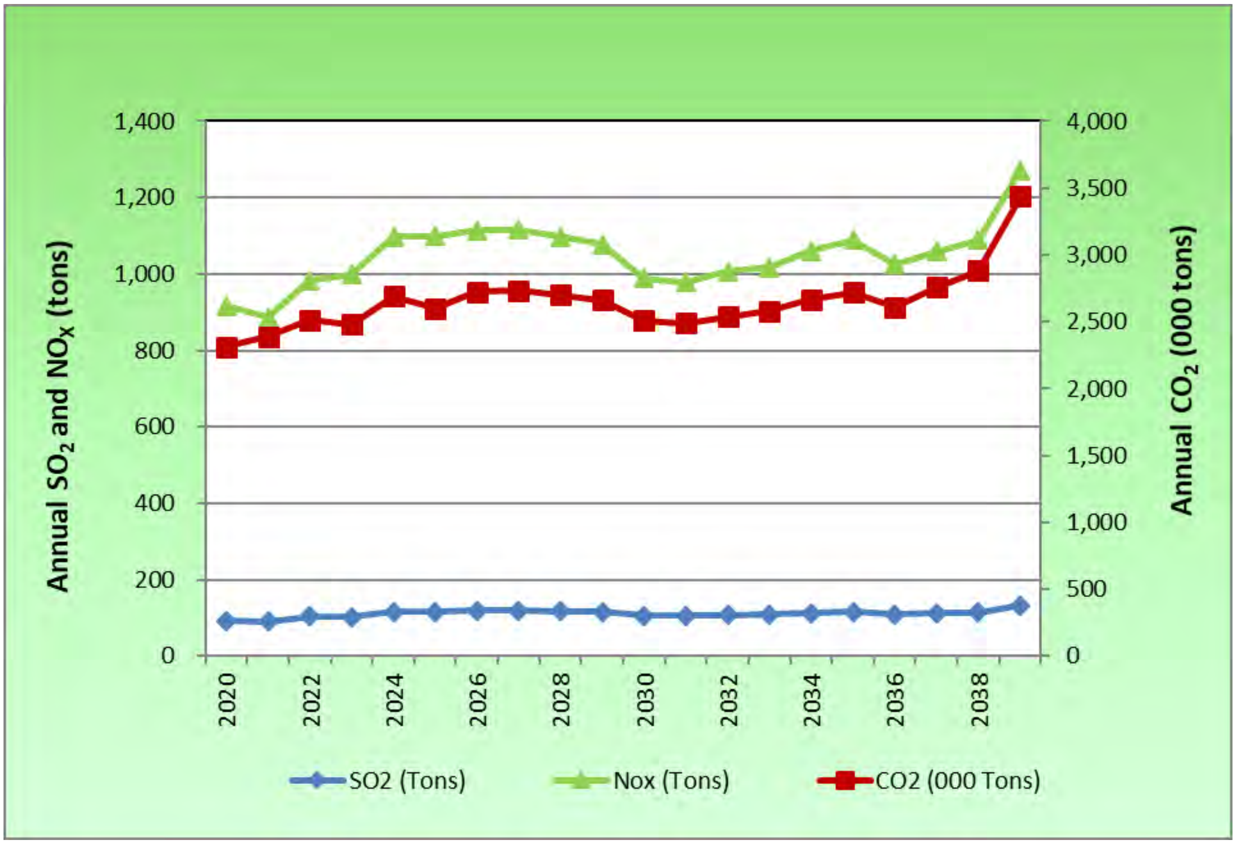


7.1.4 PREFERRED PLAN ANNUAL EMISSIONS

The expected value of annual emissions for the Preferred Plan is 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 in 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
WAACA	10,087.6	[redacted]	[redacted]
WABCA	10,089.4	[redacted]	[redacted]
WBCCA	10,094.6	[redacted]	[redacted]
WCDCA	10,094.8	[redacted]	[redacted]
WAABA	10,103.2	[redacted]	[redacted]
WAACW	10,113.3	[redacted]	[redacted]
WAADA	10,120.6	[redacted]	[redacted]
WAAAA	10,209.0	[redacted]	[redacted]
WAACD	10,250.3	[redacted]	[redacted]
WAABD	10,259.4	[redacted]	[redacted]
WAACF	10,283.1	[redacted]	[redacted]
WAACE	10,296.0	[redacted]	[redacted]
WAAED	10,447.2	[redacted]	[redacted]

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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 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%	WAACW	**10,764**
2	High	High	No	2.5%	WAACA	**10,148**
3	High	Mid	Yes	7.5%	WAACA	**10,617**
4	High	Mid	No	5.0%	WAACA	**9,980**
5	High	Low	Yes	3.8%	WCDCA	**10,224**
6	High	Low	No	2.5%	WCDCA	**9,625**
7	Mid	High	Yes	7.5%	WAACA	**10,476**
8	Mid	High	No	5.0%	WAACA	**9,918**
9	Mid	Mid	Yes	15.0%	WAACA	**10,353**
10	Mid	Mid	No	10.0%	WAACA	**9,776**
11	Mid	Low	Yes	7.5%	WCDCA	**10,022**
12	Mid	Low	No	5.0%	WCDCA	**9,482**
13	Low	High	Yes	3.8%	WAACA	**10,226**
14	Low	High	No	2.5%	WAACA	**9,722**
15	Low	Mid	Yes	7.5%	WCDCA	**10,118**
16	Low	Mid	No	5.0%	WAACA	**9,601**
17	Low	Low	Yes	3.8%	WCDCA	**9,842**
18	Low	Low	No	2.5%	WCDCA	**9,358**

The following tables represent the sensitivities for the uncertain factors by scenario/endpoint for all 13 Plans.

7.2.1 CRITICAL UNCERTAIN FACTOR: HIGH LOAD GROWTH

HIGH LOAD GROWTH

HIGH GAS

With CO2		MID CO2		LOW CO2	
Endpoint	1	Endpoint	1	Endpoint	2
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACW	10,764	WAACW	10,764	WAACA	10,148
WAACA	10,764	WAACA	10,764	WABCA	10,151
WABCA	10,766	WABCA	10,766	WBCCA	10,156
WAABA	10,771	WAABA	10,771	WAABA	10,163
WBCCA	10,772	WBCCA	10,772	WAACW	10,173
WCDCA	10,789	WCDCA	10,789	WAADA	10,184
WAADA	10,802	WAADA	10,802	WCDCA	10,197
WAAAA	10,870	WAAAA	10,870	WAAAA	10,270
WAACD	10,927	WAACD	10,927	WAACD	10,312
WAABD	10,929	WAABD	10,929	WAABD	10,320
WAACF	10,951	WAACF	10,951	WAACF	10,358
WAACE	10,964	WAACE	10,964	WAACE	10,376
WAAED	11,155	WAAED	11,155	WAAED	10,513

MID GAS

HIGH CO2		MID CO2		LOW CO2	
Endpoint	3	Endpoint	3	Endpoint	4
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACA	10,617	WAACA	10,617	WAACA	9,980
WABCA	10,619	WABCA	10,619	WABCA	9,982
WBCCA	10,625	WBCCA	10,625	WBCCA	9,988
WAACW	10,626	WAACW	10,626	WAABA	9,998
WAABA	10,627	WAABA	10,627	WCDCA	10,011
WCDCA	10,628	WCDCA	10,628	WAADA	10,013
WAADA	10,653	WAADA	10,653	WAACW	10,015
WAAAA	10,728	WAAAA	10,728	WAAAA	10,107
WAACD	10,784	WAACD	10,784	WAACD	10,147
WAABD	10,788	WAABD	10,788	WAABD	10,158
WAACF	10,798	WAACF	10,798	WAACF	10,202
WAACE	10,806	WAACE	10,806	WAACE	10,222
WAAED	11,002	WAAED	11,002	WAAED	10,337

LOW GAS

HIGH CO2		MID CO2		LOW CO2	
Endpoint	5	Endpoint	5	Endpoint	6
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WCDCA	10,224	WCDCA	10,224	WCDCA	9,625
WAACA	10,247	WAACA	10,247	WAACA	9,636
WABCA	10,249	WABCA	10,249	WABCA	9,637
WBCCA	10,251	WBCCA	10,251	WBCCA	9,642
WAABA	10,266	WAABA	10,266	WAADA	9,662
WAADA	10,276	WAADA	10,276	WAABA	9,662
WAACW	10,282	WAACW	10,282	WAACW	9,696
WAAAA	10,372	WAAAA	10,372	WAAAA	9,776
WAACE	10,374	WAACE	10,374	WAACD	9,812
WAACF	10,376	WAACF	10,376	WAABD	9,830
WAACD	10,425	WAACD	10,425	WAACF	9,844
WAABD	10,436	WAABD	10,436	WAACE	9,859
WAAED	10,613	WAAED	10,613	WAAED	9,971

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
	WAACA	10,226	WAACA	10,226	WAACA	9,722
	WABCA	10,227	WABCA	10,227	WABCA	9,724
	WCDCA	10,231	WCDCA	10,231	WBCCA	9,729
	WAACW	10,232	WAACW	10,232	WAABA	9,739
	WBCCA	10,234	WBCCA	10,234	WCDCA	9,751
	WAABA	10,236	WAABA	10,236	WAACW	9,752
	WAADA	10,262	WAADA	10,262	WAADA	9,755
	WAAAA	10,337	WAAAA	10,337	WAAAA	9,847
	WAACD	10,383	WAACD	10,383	WAACD	9,876
	WAABD	10,387	WAABD	10,387	WAABD	9,886
	WAACF	10,439	WAACF	10,439	WAACF	9,950
	WAACE	10,456	WAACE	10,456	WAACE	9,971
	WAAED	10,600	WAAED	10,600	WAAED	10,066

MID GAS	HIGH CO2		MID CO2		LOW CO2	
	Endpoint	15	Endpoint	15	Endpoint	16
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	WCDCA	10,118	WCDCA	10,118	WAACA	9,601
	WAACA	10,121	WAACA	10,121	WABCA	9,603
	WABCA	10,123	WABCA	10,123	WBCCA	9,608
	WBCCA	10,128	WBCCA	10,128	WCDCA	9,617
	WAABA	10,133	WAABA	10,133	WAABA	9,621
	WAACW	10,135	WAACW	10,135	WAADA	9,633
	WAADA	10,155	WAADA	10,155	WAACW	9,641
	WAAAA	10,236	WAAAA	10,236	WAAAA	9,731
	WAACD	10,279	WAACD	10,279	WAACD	9,756
	WAABD	10,285	WAABD	10,285	WAABD	9,770
	WAACF	10,319	WAACF	10,319	WAACF	9,836
	WAACE	10,329	WAACE	10,329	WAACE	9,859
	WAAED	10,487	WAAED	10,487	WAAED	9,936

LOW GAS	HIGH CO2		MID CO2		LOW CO2	
	Endpoint	17	Endpoint	17	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	WCDCA	9,842	WCDCA	9,842	WCDCA	9,358
	WAACA	9,860	WAACA	9,860	WAACA	9,370
	WABCA	9,862	WABCA	9,862	WABCA	9,371
	WBCCA	9,863	WBCCA	9,863	WBCCA	9,374
	WAABA	9,879	WAABA	9,879	WAADA	9,396
	WAADA	9,890	WAADA	9,890	WAABA	9,396
	WAACW	9,895	WAACW	9,895	WAACW	9,430
	WAACF	9,986	WAACF	9,986	WAAAA	9,510
	WAACE	9,986	WAACE	9,986	WAACD	9,527
	WAAAA	9,986	WAAAA	9,986	WAABD	9,546
	WAACD	10,021	WAACD	10,021	WAACF	9,572
	WAABD	10,033	WAABD	10,033	WAACE	9,588
	WAAED	10,204	WAAED	10,204	WAAED	9,680

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
WAACW	10,764	WAACW	10763.7	WAACA	10,148
WAACA	10,764	WAACA	10763.8	WABCA	10,151
WABCA	10,766	WABCA	10766.1	WBCCA	10,156
WAABA	10,771	WAABA	10770.9	WAABA	10,163
WBCCA	10,772	WBCCA	10772.5	WAACW	10,173
WCDCA	10,789	WCDCA	10789.4	WAADA	10,184
WAADA	10,802	WAADA	10802.3	WCDCA	10,197
WAAAA	10,870	WAAAA	10870.2	WAAAA	10,270
WAACD	10,927	WAACD	10927.3	WAACD	10,312
WAABD	10,929	WAABD	10928.7	WAABD	10,320
WAACF	10,951	WAACF	10951.2	WAACF	10,358
WAACE	10,964	WAACE	10964.5	WAACE	10,376
WAAED	11,155	WAAED	11155.4	WAAED	10,513

MID LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	7	Endpoint	7	Endpoint	8
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACA	10,476	WAACA	10,476	WAACA	9,918
WABCA	10,478	WABCA	10,478	WABCA	9,920
WAACW	10,480	WAACW	10,480	WBCCA	9,926
WBCCA	10,485	WBCCA	10,485	WAABA	9,934
WAABA	10,485	WAABA	10,485	WAACW	9,946
WCDCA	10,490	WCDCA	10,490	WAADA	9,953
WAADA	10,513	WAADA	10,513	WCDCA	9,955
WAAAA	10,586	WAAAA	10,586	WAAAA	10,042
WAACD	10,637	WAACD	10,637	WAACD	10,076
WAABD	10,640	WAABD	10,640	WAABD	10,086
WAACF	10,681	WAACF	10,681	WAACF	10,141
WAACE	10,697	WAACE	10,697	WAACE	10,161
WAAED	10,859	WAAED	10,859	WAAED	10,271

LOW LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	13	Endpoint	13	Endpoint	14
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACA	10,226	WAACA	10,226	WAACA	9,722
WABCA	10,227	WABCA	10,227	WABCA	9,724
WCDCA	10,231	WCDCA	10,231	WBCCA	9,729
WAACW	10,232	WAACW	10,232	WAABA	9,739
WBCCA	10,234	WBCCA	10,234	WCDCA	9,751
WAABA	10,236	WAABA	10,236	WAACW	9,752
WAADA	10,262	WAADA	10,262	WAADA	9,755
WAAAA	10,337	WAAAA	10,337	WAAAA	9,847
WAACD	10,383	WAACD	10,383	WAACD	9,876
WAABD	10,387	WAABD	10,387	WAABD	9,886
WAACF	10,439	WAACF	10,439	WAACF	9,950
WAACE	10,456	WAACE	10,456	WAACE	9,971
WAAED	10,600	WAAED	10,600	WAAED	10,066

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
WCDCA	10,224	WCDCA	10,224	WCDCA	9,625
WAACA	10,247	WAACA	10,247	WAACA	9,636
WABCA	10,249	WABCA	10,249	WABCA	9,637
WBCCA	10,251	WBCCA	10,251	WBCCA	9,642
WAABA	10,266	WAABA	10,266	WAADA	9,662
WAADA	10,276	WAADA	10,276	WAABA	9,662
WAACW	10,282	WAACW	10,282	WAACW	9,696
WAAAA	10,372	WAAAA	10,372	WAAAA	9,776
WAACE	10,374	WAACE	10,374	WAACD	9,812
WAACF	10,376	WAACF	10,376	WAABD	9,830
WAACD	10,425	WAACD	10,425	WAACF	9,844
WAABD	10,436	WAABD	10,436	WAACE	9,859
WAAED	10,613	WAAED	10,613	WAAED	9,971

MID LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	11	Endpoint	11	Endpoint	12
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WCDCA	10,022	WCDCA	10,022	WCDCA	9,482
WAACA	10,044	WAACA	10,044	WAACA	9,494
WABCA	10,045	WABCA	10,045	WABCA	9,496
WBCCA	10,047	WBCCA	10,047	WBCCA	9,499
WAABA	10,063	WAABA	10,063	WAADA	9,520
WAADA	10,074	WAADA	10,074	WAABA	9,521
WAACW	10,079	WAACW	10,079	WAACW	9,554
WAAAA	10,170	WAAAA	10,170	WAAAA	9,635
WAACE	10,171	WAACE	10,171	WAACD	9,659
WAACF	10,171	WAACF	10,171	WAABD	9,678
WAACD	10,212	WAACD	10,212	WAACF	9,699
WAABD	10,224	WAABD	10,224	WAACE	9,715
WAAED	10,397	WAAED	10,397	WAAED	9,814

LOW LOAD

HIGH CO2		MID CO2		LOW CO2	
Endpoint	17	Endpoint	17	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WCDCA	9,842	WCDCA	9,842	WCDCA	9,358
WAACA	9,860	WAACA	9,860	WAACA	9,370
WABCA	9,862	WABCA	9,862	WABCA	9,371
WBCCA	9,863	WBCCA	9,863	WBCCA	9,374
WAABA	9,879	WAABA	9,879	WAADA	9,396
WAADA	9,890	WAADA	9,890	WAABA	9,396
WAACW	9,895	WAACW	9,895	WAACW	9,430
WAACF	9,986	WAACF	9,986	WAAAA	9,510
WAACE	9,986	WAACE	9,986	WAACD	9,527
WAAAA	9,986	WAAAA	9,986	WAABD	9,546
WAACD	10,021	WAACD	10,021	WAACF	9,572
WAABD	10,033	WAABD	10,033	WAACE	9,588
WAAED	10,204	WAAED	10,204	WAAED	9,680

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
	WAACW	10,764	WAACA	10,617	WCDCA	10,224
	WAACA	10,764	WABCA	10,619	WAACA	10,247
	WABCA	10,766	WBCCA	10,625	WABCA	10,249
	WAABA	10,771	WAACW	10,626	WBCCA	10,251
	WBCCA	10,772	WAABA	10,627	WAABA	10,266
	WCDCA	10,789	WCDCA	10,628	WAADA	10,276
	WAADA	10,802	WAADA	10,653	WAACW	10,282
	WAAAA	10,870	WAAAA	10,728	WAAAA	10,372
	WAACD	10,927	WAACD	10,784	WAACE	10,374
	WAABD	10,929	WAABD	10,788	WAACF	10,376
	WAACF	10,951	WAACF	10,798	WAACD	10,425
	WAACE	10,964	WAACE	10,806	WAABD	10,436
	WAAED	11,155	WAAED	11,002	WAAED	10,613

MID LOAD	HIGH GAS		MID GAS		LOW GAS	
	Endpoint	7	Endpoint	9	Endpoint	11
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	WAACA	10,476	WAACA	10,353	WCDCA	10,022
	WABCA	10,478	WABCA	10,355	WAACA	10,044
	WAACW	10,480	WCDCA	10,356	WABCA	10,045
	WBCCA	10,485	WBCCA	10,361	WBCCA	10,047
	WAABA	10,485	WAABA	10,365	WAABA	10,063
	WCDCA	10,490	WAACW	10,365	WAADA	10,074
	WAADA	10,513	WAADA	10,388	WAACW	10,079
	WAAAA	10,586	WAAAA	10,467	WAAAA	10,170
	WAACD	10,637	WAACD	10,516	WAACE	10,171
	WAABD	10,640	WAABD	10,521	WAACF	10,171
	WAACF	10,681	WAACF	10,546	WAACD	10,212
	WAACE	10,697	WAACE	10,556	WAABD	10,224
	WAAED	10,859	WAAED	10,728	WAAED	10,397

LOW LOAD	HIGH GAS		MID GAS		LOW GAS	
	Endpoint	13	Endpoint	15	Endpoint	17
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	WAACA	10,226	WCDCA	10,118	WCDCA	9,842
	WABCA	10,227	WAACA	10,121	WAACA	9,860
	WCDCA	10,231	WABCA	10,123	WABCA	9,862
	WAACW	10,232	WBCCA	10,128	WBCCA	9,863
	WBCCA	10,234	WAABA	10,133	WAABA	9,879
	WAABA	10,236	WAACW	10,135	WAADA	9,890
	WAADA	10,262	WAADA	10,155	WAACW	9,895
	WAAAA	10,337	WAAAA	10,236	WAACF	9,986
	WAACD	10,383	WAACD	10,279	WAACE	9,986
	WAABD	10,387	WAABD	10,285	WAAAA	9,986
	WAACF	10,439	WAACF	10,319	WAACD	10,021
	WAACE	10,456	WAACE	10,329	WAABD	10,033
	WAAED	10,600	WAAED	10,487	WAAED	10,204

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
WAACA	10,148	WAACA	9979.92	WCDCA	9,625
WABCA	10,151	WABCA	9982.03	WAACA	9,636
WBCCA	10,156	WBCCA	9987.64	WABCA	9,637
WAABA	10,163	WAABA	9997.62	WBCCA	9,642
WAACW	10,173	WCDCA	10010.8	WAADA	9,662
WAADA	10,184	WAADA	10013.2	WAABA	9,662
WCDCA	10,197	WAACW	10015.4	WAACW	9,696
WAAAA	10,270	WAAAA	10106.9	WAAAA	9,776
WAACD	10,312	WAACD	10146.8	WAACD	9,812
WAABD	10,320	WAABD	10158.3	WAABD	9,830
WAACF	10,358	WAACF	10202	WAACF	9,844
WAACE	10,376	WAACE	10221.9	WAACE	9,859
WAAED	10,513	WAAED	10336.7	WAAED	9,971

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	8	Endpoint	10	Endpoint	12
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACA	9,918	WAACA	9,776	WCDCA	9,482
WABCA	9,920	WABCA	9,778	WAACA	9,494
WBCCA	9,926	WBCCA	9,784	WABCA	9,496
WAABA	9,934	WAABA	9,795	WBCCA	9,499
WAACW	9,946	WCDCA	9,798	WAADA	9,520
WAADA	9,953	WAADA	9,808	WAABA	9,521
WCDCA	9,955	WAACW	9,814	WAACW	9,554
WAAAA	10,042	WAAAA	9,905	WAAAA	9,635
WAACD	10,076	WAACD	9,936	WAACD	9,659
WAABD	10,086	WAABD	9,949	WAABD	9,678
WAACF	10,141	WAACF	10,008	WAACF	9,699
WAACE	10,161	WAACE	10,029	WAACE	9,715
WAAED	10,271	WAAED	10,120	WAAED	9,814

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	14	Endpoint	16	Endpoint	18
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
WAACA	9,722	WAACA	9,601	WCDCA	9,358
WABCA	9,724	WABCA	9,603	WAACA	9,370
WBCCA	9,729	WBCCA	9,608	WABCA	9,371
WAABA	9,739	WCDCA	9,617	WBCCA	9,374
WCDCA	9,751	WAABA	9,621	WAADA	9,396
WAACW	9,752	WAADA	9,633	WAABA	9,396
WAADA	9,755	WAACW	9,641	WAACW	9,430
WAAAA	9,847	WAAAA	9,731	WAAAA	9,510
WAACD	9,876	WAACD	9,756	WAACD	9,527
WAABD	9,886	WAABD	9,770	WAABD	9,546
WAACF	9,950	WAACF	9,836	WAACF	9,572
WAACE	9,971	WAACE	9,859	WAACE	9,588
WAAED	10,066	WAAED	9,936	WAAED	9,680

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	DELTA	PLAN	NPVRR	DELTA
WAACA	$10,088	$0	WAACA	$10,353	$0
WABCA	$10,089	$2	WABCA	$10,355	$2
WBCCA	$10,095	$7	WCDCA	$10,356	$3
WCDCA	$10,095	$7	WBCCA	$10,361	$8
WAABA	$10,103	$16	WAABA	$10,365	$12
WAACW	$10,113	$26	WAACW	$10,365	$12
WAADA	$10,121	$33	WAADA	$10,388	$35
WAAAA	$10,209	$121	WAAAA	$10,467	$113
WAACD	$10,250	$163	WAACD	$10,516	$163
WAABD	$10,259	$172	WAABD	$10,521	$168
WAACF	$10,283	$195	WAACF	$10,546	$193
WAACE	$10,296	$208	WAACE	$10,556	$203
WAAED	$10,447	$360	WAAED	$10,728	$375

7.3 IMPLEMENTATION PLAN

The Implementation Plan provided in the 2018 Evergy Missouri West Triennial IRP is materially changing due to the wind additions announced and altering the retirement date of Lake Road 4/6 from December 2019 to December 2024 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

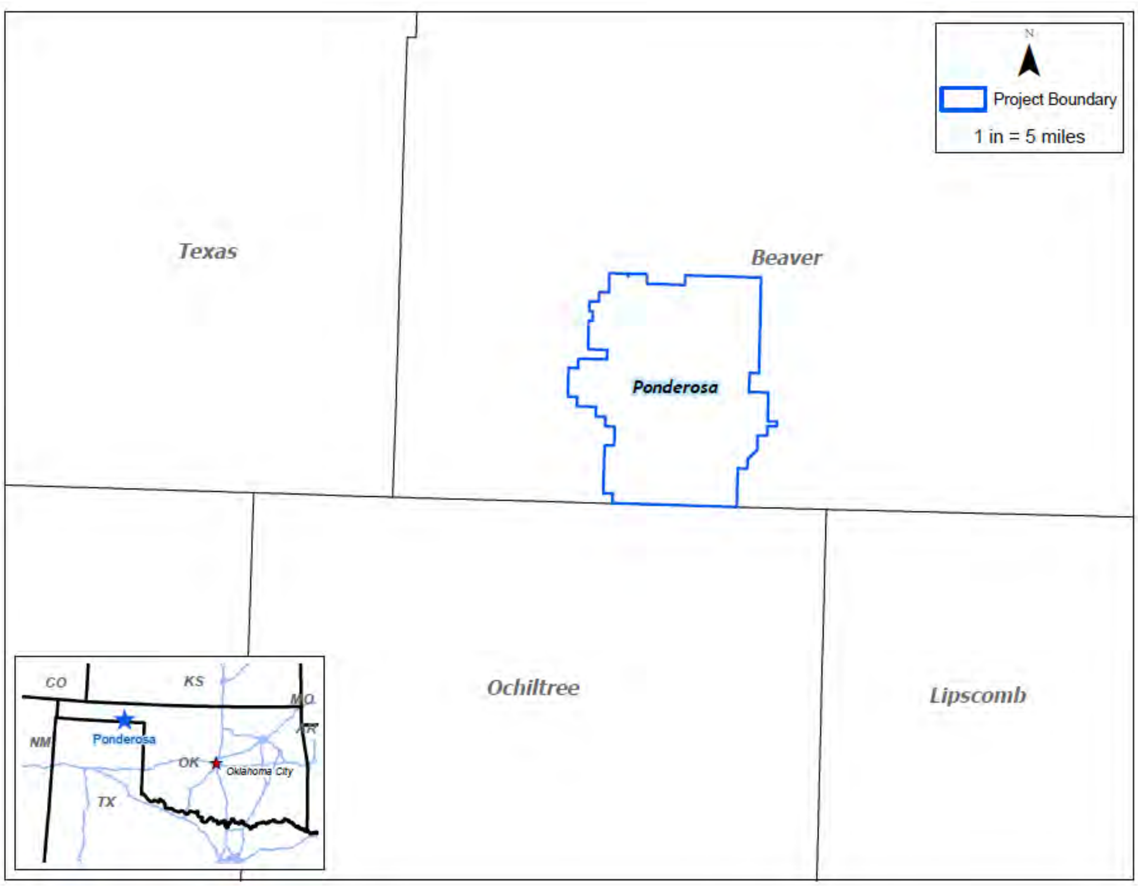
In the December 2019 Preferred Resource Plan filing statements were made that Evergy had issued a Request for Proposals (“RFP”) on November 16, 2018 to obtain and evaluate wind project offers from wind developers. The RFP responses and customer interest were such that Evergy Metro and Evergy Missouri West opted to pursue three new wind facilities totaling ~532 MWs of nameplate capacity, 125 MWs of which is currently projected to be allocated to Evergy Missouri West. The final allocation to Evergy Missouri West 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 energy 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

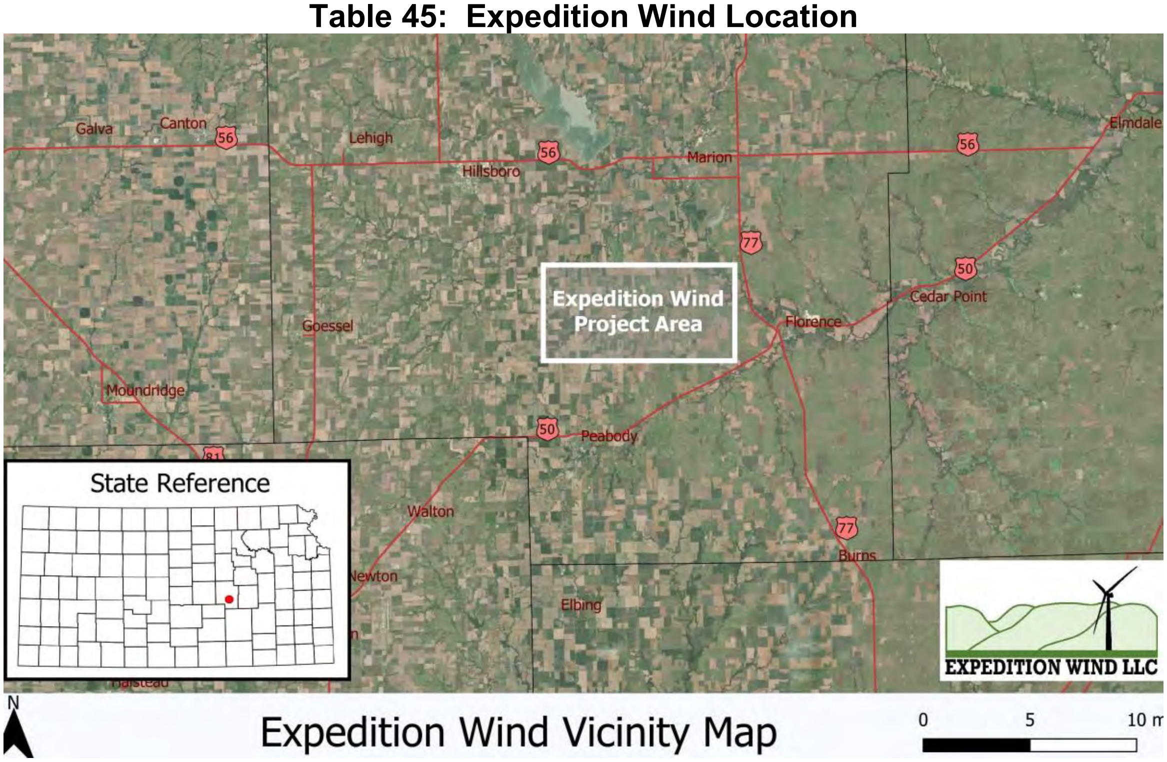


Expedition Wind is a 199 MW wind energy development with Evergy being the energy off-taker of the entire facility. The facility is currently planned to be in-service 3Q, 2021. Expedition Wind is cited over approximately 22,000 acres in Marion County, Kansas and owned by National Renewables Solutions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

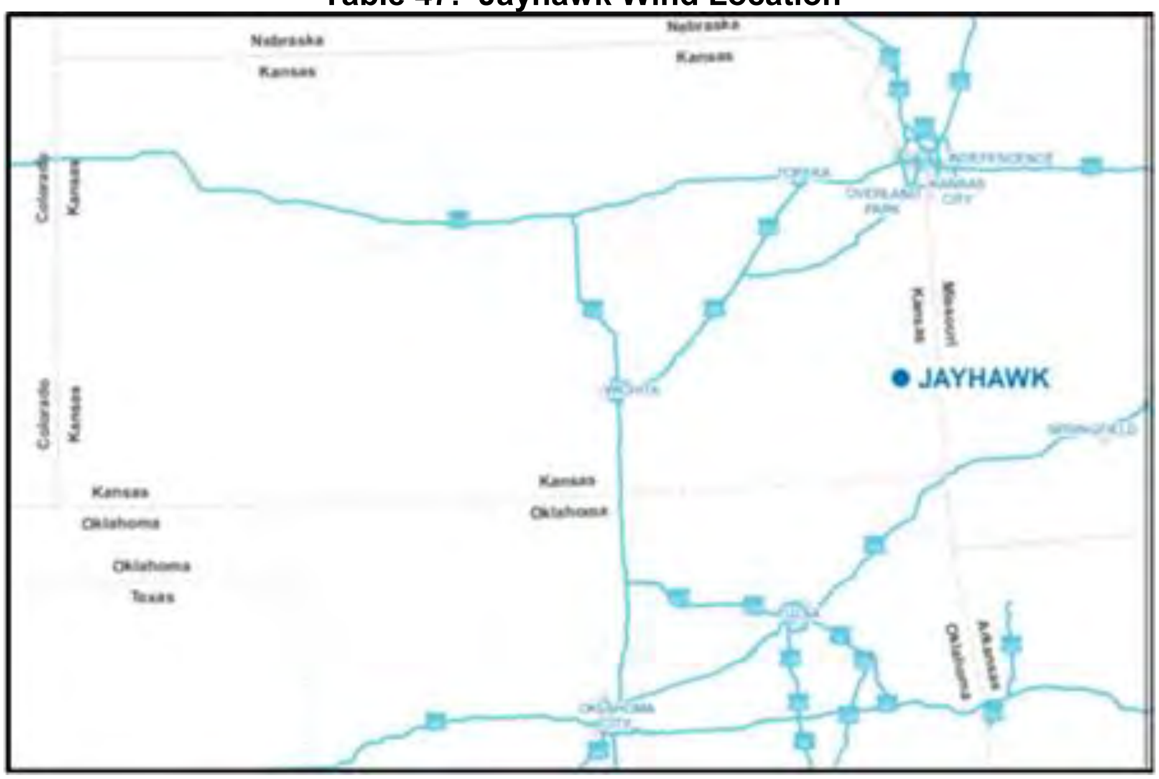


Jayhawk Wind is a 193.2 MW wind energy development with Evergy being the energy off-taker of 155 MW of the facility. The facility is currently planned to be in-service 4Q, 2021. Jayhawk Wind is cited over approximately 21,000 acres in Crawford and Bourbon Counties, Kansas and owned by Apex Clean Energy.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

The current schedules for ongoing and planned DSM programs are shown in Table 48 and Table 49 below:

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 Projects	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
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 West 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-2020-0045, the following Special Contemporary Resource Planning Issues are addressed as follows:

8.1 <u>UNCERTAIN FACTORS</u>

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 ELECTRIC VEHICLE USAGE

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.

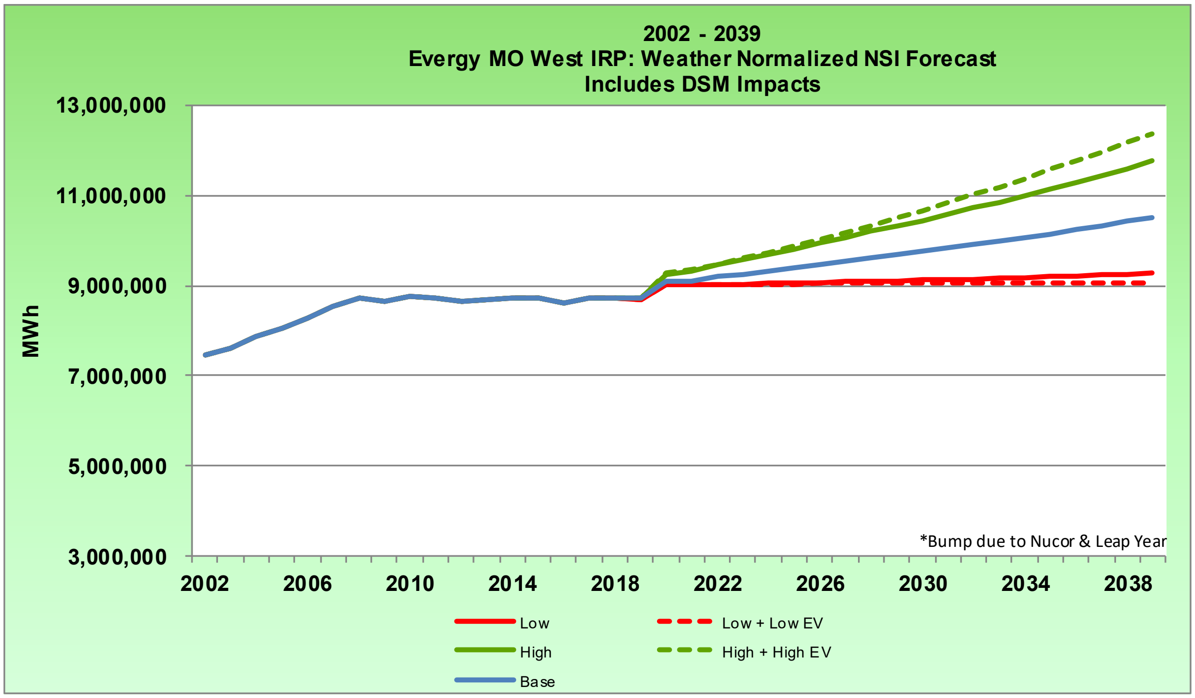
In the Evergy MO Metro base case load forecast, EV MWh usage adds 0.2% to annual usage in 2020, but grows significantly thereafter, representing 1.4% of annual usage in 2029 and 4.4% of annual usage in 2039, adding ~700k million MWh to the base case forecast in 2039.

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.

Additionally, low and high load forecast scenarios were created both with the medium adoption EV scenario as well as the corresponding low or high EV adoption scenarios as shown in Table 51 below.

Table 51: Evergy MO West 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	Upgrade Costs (in Millions) Associated with Unit / Plant Retirement Scenarios									
		Hawthorn 5	LaCygne 1	LaCygne 2	LaCygne Plant	Lawrence 4	Lawrence 5	Lawrence Plant	Jeffrey 3	Jeffrey Plant	All Plants
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 generating assets.

With the retirement of Sibley Generation Station, Evergy Missouri West is no longer in a position to retire additional coal generation. Evergy Missouri West is a minority owner in the remaining coal generation in its fleet, Iatan and Jeffery, and these facilities are unlikely to be retired anytime soon.

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 ENVIRONMENTAL CAPITAL AND OPERATING COSTS FOR COAL-FIRED GENERATING UNITS

Analyze and document the future capital and operating costs faced by each EMW coal-fired generating unit in order to comply with all existing, pending, or potential environmental standards, including until they have been finally withdrawn or replaced:

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:*** See Table 53, Table 54, and Table 55.

(3) ***National Ambient Air Quality Standards for ozone and fine particulate matter:*** See Table 53, Table 54, and Table 55.

(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:*** The Company is in compliance with this rule.

(7) ***Clean 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 Costs (2018 $ x Millions)	Jeffrey 1 [1]	Jeffrey 2 [1]	Jeffrey 3 [1]	Iatan 1 [1]
Ozone, PM and SO_2 NAAQS/Scrubber/BH	[redacted]	[redacted]	[redacted]	[redacted]
ELG-CCR/Ash Conversion	[redacted]	[redacted]	[redacted]	[redacted]

Notes
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules
[1] GMO's Share

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

Environmental Retrofit Technology Fixed O&M ($/kW - 2018 $)	Jeffrey 1	Jeffrey 2	Jeffrey 3	Iatan 1
Ozone, PM and SO_2 NAAQS/Scrubber/BH	[redacted]	[redacted]	[redacted]	[redacted]
ELG-CCR/Ash Conversion	[redacted]	[redacted]	[redacted]	[redacted]

Notes
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules

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

Environmental Retrofit Technology Variable O&M ($/MWh - 2018 $)	Jeffrey 1	Jeffrey 2	Jeffrey 3	Iatan 1
Ozone, PM and SO_2 NAAQS/Scrubber/BH	[redacted]	[redacted]	[redacted]	[redacted]
ELG-CCR/Ash Conversion	[redacted]	[redacted]	[redacted]	[redacted]

Notes
NAAQS = National Ambient Air Quality Standards
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residual Rules

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8.11 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

8.12 IMPACT OF 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.